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From: Jerry D. Smith
To: DGI Interested Parties
Date: 12/16/99 3:53pm
Subject: DGI Interconnection Standards Committee Minutes

(Reply by E-Mail if you desire to be removed from this distribution list)

As a party interested in the ACC's investigation of Distributed Generation and Interconnections you will find the following attached items concerning the DGI Workgroup's Interconnection Standards Committee:

1. Approved committee meeting minutes for Sept. 23
2. Approved committee meeting minutes for Oct 4,13, and 18
3. Approved committee meeting minutes for Nov 1, 8, 15, 18, 29.

In addition the following items that are not available in electronic form will be filed in Docket Control as accompanying meeting materials:
1. Four documents addressing "islanding" from SMUD, PSCo, Texas PUC and SRP provided by Dan Goodrich at Nov 8 meeting .
2. White paper on "Case for No Distributed Generation in the Utility Network System" presented by Carl Brittain at Nov 18 meeting.
3. White papers presented by Carl Brittain at the Nov 29 meeting and titled: "Dispatch," "Training and Certification," "Adequate Grounding," and "Time Frame and Assurance of Proper Mapping of Distributive Generation."

All of the above items will be filed in ACC Docket Control per:
Docket No. E-00000A-99-0431
General investigation of Distributed Generation and Interconnections for potential retail electric competition rules consideration.

CC: LLK

INTERCONNECTION STANDARDS MEETING NOTES

DATE: SEPTEMBER 23, 1999
LOCATION: 1200 W WASHINGTON
PHOENIX, ARIZONA
LEGAL CONFERENCE ROOM

ATTENDEES:

Chuck DeCorse (co chair)	Tucson Electric Power
Andrew Meyer	Tucson Electric Power
Bill Murphy(co-chair)	City of Phoenix
Jerry Smith	Arizona Corporation Commission
Ron Onate	Arizona Public Service
Byran Gernet	Arizona Public Service
Ernest Wakefield	Salt River Project
Kent Crouse	Southwest Gas
Caroline Gardiner	Southwest Energy Systems
Ed Gieseking	Southwest Gas
David Townley	New Energy Technology

Bryan Gernet gave out the "strawman" document of the Arizona State Interconnection Requirement for Distributed Generation. This is the working document that will be commented on prior to the next general meeting on Monday, October 4. It was agreed upon that this committee determine how to drive this document to stand the test of time.
Bryan went over the document and each section highlighting the main points of the strawman. Bryan will provide this document electronically and everyone is to make comments prior to the next meeting Oct 4. The comments are not to be sent back to Bryan but are to be discussed the afternoon of Oct 4th.

Bryan felt believed that for smaller DG a smaller, more simplied user friendly domument may be an objective for the future. Jerry's response was that until we know what form standard is to be we would want to delay on a more simplified document for small systems.

Jerry Smith gave a brief summary of a conference call among all the chairs of the committees.

1. The Access, Metering, & Dispatch will be primarily concerned with tariffs and operational issues. Jerry's comments to this group was
- That they may be preliminarily looking at tariffs.
- Metering consideration-Net metering may not be applied to one customer, there may be selling from one ESP to another.
3. Citing Certification, and Permitting-This committee is addressing Certification requirements, responsibilities for air quality, noise, etc. They will be addressing application forms. This is an area that must be addressed by the Interconnection Standards Committee also.
4. Interconnection Standards. Jerry had two concerns:
1. Packaged protection vs discrete relays-Which standards are acceptable to everyone? Dave Townley said that Capstone microturbines have UL approved inverters and Allied Signal microturbines are undergoing ETL certification for their inverters. Jerry said that manufacturers have been asking for standards from committes such as this and need to know what to do.
2. Impact on the number of distributed generators that can be interconnected with a common feeder. A general study should be pursued rather that individual studies. The fault is now at the DS rather than at the substation.

Jerry said that he is looking for a functionality approach rather than a prescriptive approach. This will be an evolution on where we are going.

There was discussion over transition switches. Experience has shown that there have been failures with a make before break transfer switch.

The interconnection requirements shall be limited to distribution systems. Interconnection to transmission systems shall be addressed in an individual basis with considerations with respect to WSCC, etc requirements. Any transmission interconnection may be the subject of a future workshop and/or document.

Future meetings will be at the ACC 1200 W Washington, Phoenix, 9:30AM to 3:00PM and are scheduled as follows:

MondayOct 4	This will be the general session in the morning and in the afternoon individual committees will meet.

Monday, Oct 11
Monday Oct 17
Monday, Oct 24
Monday, Nov 1
Monday, Nov 8
Monday, Nov 15
Monday, Nov 22
Monday, Nov29

Minutes from past minutes were approved with some corrections. Chuck DeCorse will send out corrected versions.

Chuck DeCorse

INTERCONNECTION STANDARDS MEETING NOTES

DATE: OCTOBER 4, 1999
LOCATION: 1200 W WASHINGTON
PHOENIX, ARIZONA
HEARING ROOMS 1 & 2

ATTENDEES:

Chuck DeCorse (co chair)	Tucson Electric Power
Bill Murphy(co-chair)	City of Phoenix
Jerry Smith	Arizona Corporation Commission (towards the end)
Ron Onate	Arizona Public Service
Byran Gernet	Arizona Public Service
Daniel Goodrich	Salt River Project
Kent Crouse	Southwest Gas
Caroline Gardiner	Southwest Energy Systems
Ed Gieseking	Southwest Gas
David Townley	New Energy Technology
Carl C. Brittain	IBEW 387
Linda Buczynski	City of Tucson
Bruce Buffum	Southwest Energy Solutions

The Committee began its critique and revision of the "strawman" document of the Arizona State Interconnection Requirement for Distributed Generation, which had been distributed at the meeting of September 23, 1999. Because the Sections on Scope and Definitions were covered, there was considerable discussion on overarching philosophical issues, as documented below.

Identification of the pending Standards as "minimum" was discouraged by some participants, while others felt strongly about leaving the modifier in. It was pointed out that the word was potentially misleading to readers, leaving them uncertain of when they had indeed completed all requirements. Yet leaving the word out was seen as taking a weak stand on safety. The Scope will be modified as needed to clarify the limits of these standards, and to emphasize the priority of safety.

The prospect of interconnecting with networked as well as just radial distribution systems is a point of concern with present-day field supervisors and operators. Ron Onate said that with the present relaying, existing networks are not designed to operate with customer generation. Safety and cost of retrofits were cited as possible barriers. Without being prohibitive, relay and protection requirements will have to take into consideration feeder configuration within the breakouts of generator size classes. It was pointed out that distribution system installations and upgrades in the future must be designed for multiple-sources and bi-directional operation, reflecting transactions now occurring on the level of transmission systems and evolving to function more like those systems.

It was agreed that these Standards would apply to any interconnection with the utility system, including those of units installed for commercial operation. The point was made that a Standard applicable to some should be enforceable on all. At the meeting of September 7, 1999, Jerry Smith (ACC) had stated that the distinction is that an IPP is strictly to market, and that the Committee is to deal within the retail customer context. We will need to clarify this point with Jerry.

ACTION ITEMS: Linda Buczynski will "redline" the draft Standards as discussed in today's meeting.

INTERCONNECTION STANDARDS MEETING NOTES

DATE: OCTOBER 13, 1999
LOCATION: 1300 W WASHINGTON
PHOENIX, ARIZONA
STATE PARKS CONFERENCE ROOM

ATTENDEES:

Andrew Meyer	Tucson Electric Power
Bill Murphy(co-chair)	City of Phoenix
Jerry Smith	Arizona Corporation Commission
Ron Onate	Arizona Public Service
Byran Gernet	Arizona Public Service
Ernest Wakefield	Salt River Project
Ed Gieseking	Southwest Gas
David Townley	New Energy Technology
Kevin Duggan	Capstone Turbine Corp.
Carl Brittain	IBEW, Local 387

Jerry Smith – ACC, drew a schematic of the DG interconnection and listed the functions of the interconnection, including:

- Fault Duty
- Power Flow
- Voltage Regulation
- Protection
- Feeder Switching
- Grounding

Ron Onate voiced the need for thorough engineering review and used the need for adequate grounding to assure public safety and proper operation of protective relaying as an example. This sparked discussion of the overriding need to be concerned with safe operation for the sake of utility personnel as well as site personnel and the public-at-large. Carl Brittian stated for the record that all proceedings of the Interconnection Requirements committee need to have strong foundations in safety. Bryan Gernet added that a good Interconnection Requirement will reflect safety.

Mr. Onate then asked about a mechanism for ongoing review/evaluation of the resulting DG rules. Jerry Smith indicated that review on an as need basis may be adequate, as this may lead to discussions taking place in a more timely fashion than if they were tabled for a periodic review. Mr. Smith went on to remind the committee that interconnection requirements need to reflect a deregulated utility environment.

There was a sense among some attendees that the October 4 committee meeting may have been inadvertently redirected which lead to a sense of confusion at the start of this day's proceedings. Mr. Smith mentioned that it was not his intention for any comments he made that day to have had that effect.

Mr. Brittain was also concerned regarding a statement comparing electrical transmission systems with distribution systems. Evidently, the only comparison that was intended was that a radial system with DG behave in some ways like a loop transmission system that normally has generation interspersed with load centers.

David Townley pointed out that any interconnection document needs to provide unambiguous information to the DG manufacturers that will influence them to integrate these requirements in their designs.

The committee went on to discuss Section 3. "DEFINITIONS", of the draft Requirements. The significant revisions included the use of the term "common coupling" in the definition of Item 3.4, "Point(s) of Interconnection"; elimination of Item 3.10 " Protective Devices, Relays and Interconnection Requirments" as these topics are already defined in the scope of the document. Item 3.11 "Utility Distribution System (UDS)" was eliminated because of the general understanding of what constitutes a "distribution system". Item 3.12 "Parallel Operation" and Item 3.13 "Customer" were simplified to denote a requirement for interconnection with the Utility's system. Item 3.14 "Industrial Grade Relays" was struck as no definition was available. Item 3.15 "Utility Grade Relays" were defined as devices type tested per IEEE Standard 37– 1989, Sect. 90.0 thru 90.2.

Attention then moved to discussion of Section 8 "INTERCONNECTION TECHNICAL REQUIREMENTS". The preamble was modified slightly to eliminate the term "minimum requirements" and to emphasize safety. Discussion concluded for the day with review of Item 8.1.2. "Multiple generator connections…single Disconnect Switch…". Review of this item and further discussion of Sect. 8 will continue at the next scheduled meeting.

Bryan Gernet agreed to incorporate the resulting revisions and will make them available prior to the next meeting.

The next meeting of the Interconnection Requirements committee is scheduled for 9:30am, Monday, October 18, 1999, in the ACC Commissioner's 2nd Floor Conference Room, # 202, 1300 W. Washington, Phoenix.

Andrew Meyer
Tucson Electric Power Co.

Arizona Corporation Commission Interconnect Standards Committee Meeting

October 18, 1999

DRAFT MINUTES

ATTENDEES: Chuck DeCorse TEP), Bryan Gernet (APS), Carl C. Brittain (Local 387 IBEW (APS), Daniel Goodrich (SRP), Bill Murphy (City of Phoenix), Kent Crouse (SWG), Linda Buczynski (City of Tucson), Ray Williamson (ACC), Jeff Sams (SSVEC), Kevin Duggan (Capstone Turbine Corp.) Jerry Smith (ACC), Bob Baltes (BVA).

1. Chuck De Corse said that he has tried to get the coops in the loop, encouraging participation. Linda Buczynski has spoken to Trico in this regard. It was good to see Sulphur Springs represented by Jeff Sams today. Chuck will send Linda Buczynski a list of coop contacts so that it can be documented that this Committee has at least circulated a preliminary Interconnection Standard for review.

2. It was clarified that although the Committee is to recommend standards without voltage limitation, the document which it is presently working on addresses interconnection at the distribution level.

3. It was clarified that although the Committee is dealing with interconnection to utility systems within a retail context, the Interconnect Standards may have commercial applications.

4. A revised draft was handed out for the Scope and Definitions sections of the strawman interconnect standards.

5. Continuing with the strawman document, Section 8.1, General Technical Requirements: the communication and telemetering referred to in section 8.1.3 is related to a potential need for transfer tripping. A communication or telemetry may be required where transfer tripping is needed due to an application where a GF or aggregate of GF's are of sufficient size to supply the minimum load of the utility distribution feeder. The customer responsibility referenced in section 8.1.7 applies to equipment on the customer's side of interconnection.

6. The Committee reviewed language offered by David Townley regarding disconnect switches, Section 8.2. It was agreed that reference to a disconnect switch as having load break capability should be expanded to indicating it must be gang operated for multiple phase application. It was pointed out that fire and building safety requirements of local jurisdiction may also be a factor in location or requirement of this device.

7. There was some speculation and concern about the state-of-the-art technical capabilities of relaying and protection packages. It is important to take new developments into account, while at the same time assuring that there is to be no compromise on safety. The point was raised that there is no track record on these new packages. It is also very important for utility line crews to be able to visually and literally verify that a source has been disconnected. In order to give this Committee a better

sense of the current state of technology, there will be a guest speaker next Monday from Encorp, who will discuss the control issue, and protection too. Kevin from Capstone will also dig out its UL-listing, possibly before the next meeting.

8. While reviewing the Definitions Section, it was proposed that this Committee produce a list of pre-testing requirements, to be forwarded to the Siting, Permitting, and Certification Committee. In any case all new applications must functionally comply with the ANSI and IEEE standards for Utility Grade Relays. And it should be noted that Utility Grade Relays apply only to Class III and Class IV applications.

9. It was proposed to build a revision period into the document, in order to accommodate new technologies as they become available and after they have proven themselves.

10. The question was raised about how the incremental addition of multiple sources on a utility feeder would be accommodated by the utility. Jerry Smith offered that the treatment would be analogous to the present-day treatment of additional load on a feeder.

11. Section 8.3, Dedicated Transformer: discussion centered around the justification of 10 kW as a threshold for requiring a dedicated transformer. There were differing opinions regarding why the transformer was needed – fault contribution to neighboring customers on a common transformer, power quality (harmonics, etc.) or operational preferences for isolating interconnection of larger generator unit sizes. Applicability of the 10 kW threshold for all Arizona utilities was also questioned. It was recognized that this Committee would not simply borrow from existing documents the 10 KW standard for threshold of source size. Concurrence on the acceptable threshold was not reached in today's meeting. The 10 kW is not totally "arbitrary", but is a fairly universally accepted standard based on (a)what could reasonably lead to potential isolation at the secondary level and (b) the unlikelyhood of generators below this size adding any significant additional ground fault current to an adjacent customer services. It was agreed that Chuck and Brian will look into this question in some more detail, conferring with their in-house people and checking with the on-going IEEE work on the subject.

12. Power Quality Section 8.4: The IEEE Standard 519-1992 referenced in this section applies to harmonics and should be relocated to the associated harmonic paragraph. While it was suggested customers with load and generation should be held to the same power quality requirements; it was also recognized that distributed generators can contribute to power quality improvements. This contribution should be encouraged rather than constrained.

Compliance measures for both customers and utilities alike are lax. Bill Murphy cautioned against holding a Customer to a higher standard solely because it had an interconnected source. Bill cited as examples under PURPA certain entities had to adhere to power factor "requirements" which were not enforced for other customers. It was even questioned why Power Quality had validity as a section; TEP responded that Power Quality needs to be addressed or there would be an obstacle in approval of the Committee recommendations. It was suggested that a Table be made for each service territory. Bob Baltes will redraft this Section with Bill Murphy, reflecting the consensus of this Committee.

13. The next meeting will be held on Monday, October 25. In the morning the entire Workgroup will meet. Linda will put together some outline bullets for Chuck and Bill to present, consisting of a brief report on the progress of the Committee, outstanding issues, and coordination issues with the other committees.

ACC Special Open Meeting:
Distributed Generation & Interconnections Workgroup
Interconnections Standards Committee

Date: November 1, 1999
Time: 9:30 AM
Location: Pipeline / Safety Conference Room
1200 W. Washington
Phoenix, AZ 85007

Purpose: Continue committee investigation of interconnection standards for distributed generation.

AGENDA

1. Approve minutes of Oct 25, 1999
2. Continue and attempt to complete "strawman" document.
3. Set up sub committees to expedite completion of document.
4. Begin to establish a format for final document for ACC submittal of November 22.

Arizona Corporation Commission Interconnect Standards Committee Meeting

November 8, 1999

ADDENDUM TO DRAFT MINUTES

ATTENDEES: Chuck DeCorse TEP), Bryan Gernet (APS), Carl C. Brittain (Local 387 IBEW (APS), Daniel Goodrich (SRP), Bill Murphy (City of Phoenix), David Townley (NE), Jeff Sams (SSVEC), Kent Crouse (SWG).

1. The committee reviewed and made final comments on Linda Buczyski's revised meeting minutes from 11/1/99.

2. It was agreed that in order to better track consensus on the specific document changes which were reached during the meeting, the changes would be specifically noted in the minutes.

3. In section 8.7.1.5, it was agreed that the term "breaker" would be changed to "breaker/contactor". David Townley suggested adding language to reflect that if a unit was tripped off line due to a control power failure, that the unit could be automatically reclosed once control power was regained.

4. The group discussed and re-verified that <u>supervisory control</u> was not required for Class II applications.

5. In order to resolve disagreement over when supervisory controls are required, Consensus was reached to include David Townley's language changes to sections 8.7.2.3 #4 and 8.7.2.4 #6. The language is to be added after the word "necessary" at the end of the first sentence and is as follows: "this is especially true when the GF is large relative to the minimum line load; or involved in power transactions requiring the grid; or remotely switched on or off by the utility." Bryan Gernet will work this change into the document.

6. Daniel Goodrich presented a memorandum with supporting documentation materials from Public Service Company of Colorado and SMUD which more clearly defined islanding and protection requirements due to islanding. Daniel further suggested minor changes to section 8.1.3 which would address the islanding concerns. Consensus was reached to implement the changes per Daniel's memorandum. The attached definition of islanding will also be added to section 3.

7. Bryan Gernet discussed that he had spoken outside of the committee with Jerry Smith regarding the power quality section. Their belief is that it would be easier to maintain the specific power quality requirements in an exhibit referenced by the document. This will allow easier maintenance of the document in the future. The group agreed with this recommendation.

8. Bill Murphy agreed to complete the proposed Exhibit A attachment which will contain the power quality specifications for each utility. Jeff Sams provided SSVEC's

specifications, Daniel Goodrich provided SRP's specifications, and Chuck Decorse provided TEP's specifications.

8. Daniel Goodrich agreed to develop the proposed Exhibit B which will contain a table of the specific relay settings requirements for each utility.

9. The group moved into section 10 to discuss the application process. Bryan Gernet has been working with the Siting and Permitting Committee and has found that they want a more complex application process than is in the current APS document. It was agreed that the Interconnection Committee should have the opportunity to review the final application process recommendation of the Siting and Permitting Committee. (action item for Jerry Smith)

10. Bryan is to communicate with the Siting and Permitting Committee on the timeframe to review and approve the application. (another action item for Bryan)

11. Consensus was reached to change language in section 11.1. The word "minimum" is to be removed from the first sentence and the wording, "protective relay trip function" is to be changed to "protective device function".

12. David Townley requested and the committee agreed to delete the words "prior to" in the second sentence of section 11.4.

13. Bryan Gernet will add language to section 11 which will allow the utility flexibility to assist homeowner DG customers in testing of the protective devices prior to interconnection.

14. It was agreed that there is concern warranted over demand charge ratcheting that could occur under certain rate structures if the utility mandated taking a GF down for relay (protective device) testing. This is identified as an item that needs to be resolved by the Access and Metering Committee. (action item Jerry Smith)

15. There was a great deal of discussion over safety concerns and generator damage due to disconnect switch reclosure onto an energized circuit by utility personnel. The major question is what should occur prior to reclosing. It was agreed that the best way to protect all parties is to verify that there is no voltage on the customer side of the disconnect switch. Bryan Gernet will assemble language regarding labeling the disconnect switch where it has the potential to be closed onto an energized circuit. The language will be placed in section 12.5

16. Bryan Gernet is to send via email the most recent revision of the complete Interconnection document prior to the 11/15/99 meeting.

17. The group agreed to extend every effort to complete sections 3, 8, 11, 12 and Exhibit A for the 11/15/99 meeting in order that the strawman document can be made available to the other committees at the next joint meeting on 11/22/99. These sections should be in essentially a completed form following Bryan Gernet's revisions from this meeting.

Meeting Minutes of November 15, 1999 Attendees:

Attendees	
Chuck DeCorse	Tucson Electric Power
Ron Onate	Arizona Public Service
Bryan Gernet	Arizona Public Service
Bill Murphy	City of Phoenix
David Townley	New Energy
Dan Goodrich	Salt River Project
Carl Brittan	Arizona Public Service, IBEW
Jerry Smith	Arizona Corporation Commission

1. Minutes of November 8, 1999 were amended and approved.
2. Definition of "islanding" was submitted by Dan Goodrich and approved by the committee to be more consistent with the IEEE SCC21 working group definition.
3. Revised working document, Arizona State Interconnection Requirements For Distributed Generation DRAFT, (ASIRDG) was handed out to committee by Bryan Gernet. Changes as a result of the November 8 meeting were discussed and changes accepted along with the word "protective" added before "Relay" in 8.7.1.5 (a) and (b).
4. Exhibit A, Power Quality Requirements handed out to committee by Bill Murphy. These requirements are to be filled in by APS, SRP, TEP, and SSVEC.
5. Exhibit B, Utility Relay Settings and Re-closing Practices to committee by Dan Goodrich. These requirements are to completed by APS, SRP, TEP, and SSVEC.
6. There will be references in a seperate section stating which standards this document is to use, such as IEEE, ANSI, UL, NEC, NESC, etc.
7. Power Quality requirements for distributed generation should not exceed or be less than those requirements in Exhibit A.
8. Section 9, of the ASIRDG, Metering Requirements, was not addressed and is to be referred to Access Workshop Committee.
9. Section 10, Appliation Process and Documentation Requirements, of the ASIRDG, was accepted by the committee.
10. Section 11,Testing and Start-up Requirements, of the ASIRDG, was accepted, with minor changes, by the committee.
11. Section 12.4, of the ASIRDG, was discussed and section (d) was to include "or hold tag" added after "clearance". Carl Brittan and Dan Goodrich were assigned to establish definitions of "hold tag", "clearence" and "multi-clearance", referencing safety manuels,or system operating standards.
12. Item 12.5, of the ASIRDG, was unresolved because responsibility of reclosing of switch was not determined.
13. Appendix A of the ASIRDG, was accepted by the committee with minor changes. This section, and two other "white papers" was included as information and reference to the Siting and Permitting Committee. This may provide some guidance on times and processes to implement DG and interfacing with the utility for connection to the grid.
14. Supplementary Information of the ASIRDG was accepted by the committee with

minor changes.

14. One more meeting was scheduled to close items that are unresolved. A conference call is scheduled on Thursday, November 18 in the ACC offices in Phoenix, the ACC offices in Tucson, and members attending a meeting at Westin La Paloma in Tucson. The unresolved items are Networks systems and DG, Dedicated transformers and item 12.4 of the ASIRDG.

Chuck DeCorse (co-chair)

Meeting Minutes of November 29, 1999

Attendees:

A. Phoenix ACC

Bryan Gernet	Arizona Public Service
Ron Onate	Arizona Public Service
Dan Goodrich	Salt River Project
Carl Brittan	Arizona Public Service-IBEW
Jeff Sams	Sulphur Springs Valley Electric Coop
Mike Schwindenhammer	Sulphur Springs Valley Electric Coop
Chuck DeCorse	Tucson Electric Power
Bill Murphy	City of Phoenix
Daniel Goodrich	Salt River Project
Sharon Madden	Arizona Public Service (part time)
Dave Townley	New Energy (phone patch)

Reference: Arizona State Interconnection Requirements for Distributed Generation DRAFT. (Strawman)

Comments were sent out via E Mail and were sent to Bryan Gernet. Bryan handed out the revised strawman.

Carl Brittan passed out the following White Papers:

1. Dispatch, dated Nov 24, 1999. This paper stressed the importance of DG's and dispatch office working together and providing accurate records on the system.
2. Training and Certification, dated Nov 23, 1999. This paper referred to the next referenced paper and emphasized the importance of training and certification.
3. Training and Certification, by Jim Corbin, President, IBEW local 1116, dated Sept 14, 1999. This paper provided insight on the training of utility personnel to acquire journeyman status for working on the power grid. This paper reasoned and recommended minimum standards to acquire certification for interconnection for DG to the grid.
4. Adequate Grounding at Distributive Generation Sites, dated Nov. 23, 1999. This paper discussed importance of proper grounds for DG.
5. Time Frame and Assurance of Proper Mapping o Distributive Generation, dated Nov 23, 1999. The paper discussed the importance of keeping DG information up to date on UDC mapping.
6. Adequate Lightning Protection, dated Nov 23, 1999. This paper stressed the importance of lighting and surge protection.

Bryan discussed sections 1, 2, 3, and 4 without many comments from the IS Committee.

Section 6 had some comments on who was to pay (the customer of the UDC) for studies for interconnection of customer's generation. Wording was agreed on to the agreement of committee members.

Section 6.3 was rewritten to accommodate the deletion of sections 6.6 and 6.7. Sharon Madden is to rewrite this section.

Section 7 was agreed on with some minor changes.

Section 8 was agreed on with some minor changes.

Exhibit 1-Load Characteristics for Arizona Utilities. This table was changed to delete Phase Voltage Imbalance and add note (3). Table was filled out.

Exhibit 2-Utility Relay Settings and Re-closing Practices. This table was accepted and updated with minor changes.

Bryan Gernet submitted a white paper titled DG Application Process. This is part of the Interconnection Standard and given as Exhibit 3.

The meeting was adjourned and the final document is to be sent to Jerry Smith of the ACC the following day (Nov 30) incorporating all comments.

Chuck DeCorse (co-chair)

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ARIZONA CORPORATION COMMISSION

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Director of Utilities

GOODRICH DANIEL A

From: GOODRICH DANIEL A
Sent: Friday, November 05, 1999 2:09 PM
To: 'cdecorse@tucsonelectric.com'
Subject: Islanding issue

Chuck, I'll bring copies of this e-mail to Monday's meeting. I propose the following:

In the definitions, add **Islanding**: An operating condition whereby a portion of the Utility's other loads becomes disconnected from the Utility, but is still connected to the Customer's Generating Facility. Unless agreed to beforehand by both the Utility and the Customer, this is considered an unacceptable condition.

I don't think there is a need to add any language to 8.7.2, but 8.1.4 (which might now be 8.1.3) can be changed to (changes are shown in ***italics***):

In the event that a generator, or aggregate of generators, are of sufficient size to carry the entire (minimum) load of the utility distribution feeder, or if a generator size and physical location on a feeder ***are such that islanding is reasonably possible***, then a transfer trip scheme ***(or reverse power protection if the generator does not export power)*** may be required at the Customer's expense. In certain instances...

Daniel Goodrich
Assistant Project Manager for Year 2000/Distribution Operations
Phone (602) 236-6485, Fax 236-6411, Mail Station POB-003
e-mail dagoodri@srpnet.com

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1.4 SEPARATE SYSTEMS

A separate system is defined as one in which there is no possibility of connecting a Producer's generating equipment in parallel with PSCo's system.

This can be accomplished by either an electrically or a mechanically interlocked switching arrangement which prevents the two power sources (PSCo and Producer) from serving a power load simultaneously.

If a Producer has a separate system, PSCo will require verification that the transfer scheme meets the non-parallel requirements. This will be accomplished by approval of drawings by PSCo in writing and, if PSCo so elects, by field inspection of the transfer scheme. PSCo will not be responsible for approving a Producer's generation equipment and assumes no responsibility for its design, operation or effects on Producer's loads (see Liability Section 1.6). For further information on automatic throwover requirements, please refer to the PSCo Electric Distribution Department's "Statement of Requirements for Customer Owned Secondary Automatic Throwover (ATO) Equipment."

1.5 PARALLEL OPERATION

A parallel system or parallel generation is defined as one in which a Producer's generation can be connected to PSCo's system. A transfer of power between the two systems is a direct and often desired result. All revenue generating Producers or QFs are connected in parallel with PSCo.

Utility lines are subject to a variety of natural (lightning, wind, ice) and man-made hazards. The electric problems which can result from these hazards are principally short circuits, grounded conductors, and broken conductors. These fault conditions require that the equipment involved be de-energized as soon as possible because of the hazards they pose to the public and to the operation of the system. A parallel generator must have adequate protective devices installed to sense trouble on the utility system and promptly disconnect from all sources.

Parallel generation can also cause another condition known as "accidental isolation" or "islanding" in which a portion of PSCo's load becomes isolated from PSCo but is still connected to a Producer's generator(s). In this condition, the isolated system may continue to operate independent of PSCo but probably with abnormal voltage and/or frequency. Accidental isolation or islanding is avoided by having the correct protective relaying installed by the Producer.

The protective devices and other requirements imposed by PSCo in the following sections are intended to disconnect the parallel generator when trouble occurs. These requirements are minimal for a small installation but increase as the amount and complexity of the generation increases.

The general and specific requirements for parallel generation installations of various sizes are discussed in the following sections.

1.6 LIABILITY

This section is a guideline for the responsibilities and liabilities between PSCo and Producer.

SMUD 1995
(2)

installations the intertie protection schemes used must be more responsive to minimize damage and insure safety, yet secure to prevent false trips which may adversely impact the SMUD system.

Island

Of significant importance, is whether the proposed generator could become isolated with, and continue to supply power, to a portion of the connected distribution or transmission system. This condition known as "islanding" can cause various operating and safety problems and is not tolerable. Thus, similar units could have different protection requirements depending on the amount of load with which the unit could become isolated with.

3 Static Power Converter Systems Utility Intertie Protection

The following are requirements necessary for safe interconnection to the utility under both normal and abnormal conditions. The primary intent is to ensure that customer owned generation systems comply with applicable codes, do not pose a hazard to other customers or utility personnel, and do not compromise the reliability or restrict the operation of the utility electrical system.

The energy sources possible for Static Power Converters are

- Photo-voltaic Arrays
- Fuel Cells
- Windmills
- Batteries

In most cases the electrical energy produced is direct current, dc, which must be converted to alternating current, ac, for connection to the electric utility network.

The primary purpose of the Static Power Converter (SPC) is to perform the energy conversion, control the conversion process, and to protect both itself and the energy source from damage.

This standard applies to systems of total ratings in size up to 50 kW and includes both single and three phase systems using any Energy Source. It is apparent that the largest systems under this scope (greater than 5 kW at each installed site) may have potential for adversely impacting the utility system in some scenarios and therefore, will require more extensive and sophisticated protection equipment and system studies prior to installation, while systems at the lower end of the range (less than 5 kW at each installed site) in most cases would not require such extensive protection equipment and system studies.

The low end range of this application includes small single phase, residential size systems ranging in size from 1 to 5 kW. Because of the relative simplicity of the requirements for low end range systems standard general application requirements can be developed for these systems that are applicable for all single phase static power converter of 5 kW or less rated output power that are powered by single or multiple energy sources.

3.1 General Requirements

In order for a Static Power Converter to serve the required protective functions, it will need an interface protection package that must be designed to provide the protection for the following

- Open for phase and ground faults within its protective zone
- Prevent overload of any utility facilities
- Open when voltage is out of tolerance
- Open when frequency is out of tolerance
- Prevent energizing of a dead distribution circuit

SMUD 1995

(3)

Costs for installing, maintaining and/or rearranging such equipment will be borne by the NUG requesting the equipment.

4.14 Direct Transfer Tripping (DTT)

SMUD substation relaying and the relaying at the NUG's interconnection facility are designed to prevent island operation of the NUG's generation with SMUD customers. In certain instances, the protective devices specified will provide a window of operation should the NUG and the SMUD customers become isolated from the utility grid. If the NUG island system stays within the limits of these devices, then island operation would continue indefinitely. This is an unacceptable condition. Consequently, some form of transfer trip may be required to insure the NUG is de-energized due to a system fault to prevent the creation of an island system.

Island

In situations where the generator is on a circuit fed from a transformer bank and the bank's minimum load is equal to or less than 200% of the generator nameplate rating; or the unit is capable of supplying an isolated load and the ratio of load to generation is less than 2 to 1, a direct transfer trip (DTT) from the high-side interrupting device (circuit breaker) and SMUD substation feeder breaker will be installed. A unit is capable of supplying load if 1) it is a synchronous unit or, 2) it is an induction unit with sufficient capacitance to cause self-excitation.

In addition, DTT may be used to provide a trip signal to NUG from the SMUD substation, and to block automatic reclosing of the SMUD source breaker when the NUG inter-tie breaker is closed. This requires the use of two sets of DTT from both terminals to the NUG and two synch check relays to insure proper reclosing after a fault. The direct transfer trip provides:

- A direct trip of the NUG for any fault detected by SMUD relaying.
- A method to block reclosing of SMUD source breaker until the NUG has opened.

The system shall be arranged to send a trip signal directly to the NUG for any condition that opens the SMUD source breaker. The reclosing of the SMUD source breaker is modified so that receipt of the "Permissive to Reclose" (PTR) signal from the NUG will allow normal reclosing. The PTR signal is sent by the NUG whenever at least one circuit breaker (between the generator and the SMUD system) is open.

4.15 Substation Relaying, Control and Equipment Modifications

Usually the existing substation line relaying will not be adequate to protect a line with NUG generation. At a minimum, the relays will have to be recalibrated or exchanged for similar units with different ranges.

All existing single-phase fault interrupting devices located in series between the high voltage side of the NUG's main step-up transformer and SMUD's substation must be replaced with 3-phase fault interrupting devices. This is to minimize the possibility of creating a single-phasing condition.

In situations where the NUG's generator is on a distribution circuit served from a high-side fused transformer, the transformer primary protection will be modified with a 3-phase fault interrupting device, if necessary.

Increased fault duties and X/R ratios resulting from NUG's interconnection, will require substation circuit breakers be reviewed for adequate interrupting capability and withstand and, if necessary, replaced with higher rated units.

TEXAS

4

within the visible flicker stated in subsection (c)(2) of this section. Otherwise, the customer may be required to install hardware or employ other techniques to bring voltage fluctuations to acceptable levels. Line-commutated inverters do not require synchronizing equipment. Self-commutated inverters whether of the utility-interactive type or stand-alone type shall be used in parallel with the utility system only with synchronizing equipment. Direct-current generation shall not be operated in parallel with the utility system.

(3) **Protective Function Requirements.** The protective function requirements for three phase facilities of different size and technology are listed below.

(A) Facilities rated ten kilowatts (kW) or less must have an interconnect disconnect device, a generator disconnect device, an over-voltage trip, an under-voltage trip, an over/under frequency trip, and a manual or automatic synchronizing check (for facilities with stand alone capability).

(B) Facilities rated in excess of 10 kW but not more than 500 kW must have an interconnect disconnect device, a generator disconnect device, an over-voltage trip, an under-voltage trip, an over/under frequency trip, a manual or automatic synchronizing check (for facilities with stand alone capability), either a ground over-voltage trip or a ground over-current trip depending on the grounding system if required by the company, and reverse power sensing if the facility is not exporting (unless the generator is less than the minimum load of the customer.)

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(C) Facilities rated more than 500 kW but not more than 2,000 kW must have an interconnect disconnect device, a generator disconnect device, an over-voltage trip, an under-voltage trip, an over/under frequency trip, either a ground over-voltage trip or a ground over-current trip depending on the grounding system, if required by the company, an automatic synchronizing check (for facilities with stand alone capability) and reverse power sensing if the facility is not exporting (unless the facility is less than the minimum load of the customer.) If the facility is exporting power, the power direction protective function may be used to block or delay the under frequency trip with the agreement of the utility.

(D) Facilities rated more than 2,000kW but not more than 10,000 kW must have an interconnect disconnect device, a generator disconnect device, an over-voltage trip, an under-voltage trip, an over/under frequency trip, either a ground over-voltage trip or a ground over-current trip depending on the grounding system, if required by the company, an automatic synchronizing check and (AVR) for facilities with stand alone capability, and reverse power sensing if the facility is not exporting (unless the facility is less than the minimum load of the customer.) If the facility is exporting power, the power direction protective function may be used to block or delay the under frequency trip with the agreement of the utility. A telemetry/transfer trip may also be required by the company as part of a transfer tripping or blocking protective scheme.

6

2. Relay, metering, and telemetering (applicable if cogeneration) functional drawing: This is a diagram that indicates the functions of the individual relays, metering, and telemetering equipment, if any. For simple systems, the one-line drawing and functional diagram can be combined.

3. Circuit breaker control drawings: These show the conditions, relays, and instrument transformers that cause each breaker to open and close. They should indicate the source of power for each control.

4. Three-line diagram: This diagram shows voltage transformer (VT) and current transformer (CT) ratios and details of their configuration, including relays, meters, test switches, etc.

5. A written description of operation and control procedure for the generating facility: Included in this document should be a statement specifying whether or not the customer plans to sell power to SRP.

6. Manufacturer's switchboard fabrication details: At least four copies are required prior to ordering switchboard.

7. One-line electric metering and/or telemetering diagrams: This diagram may be incorporated in the one-line diagram.

8. Grounding drawings: These drawings show ground wire sizes, bonding and connections.

D. Approval

System approval occurs in several stages as listed below. The minimum times indicated for SRP's completion of each stage should be allowed:

1. Review relay and metering functional diagrams and one-line diagram. (Two weeks)

2. Review bill of materials for relays and switchgear prior to ordering equipment. (One week)

3. Review switchgear control drawings. These include circuit breaker control drawings and three-line drawings. (One week)

4. Review list of relay settings and VT and CT ratios. (One week)

5. Customer trip-tests system and submits written results to Customer Power Use Service. (One week)

6. Field verification of relay settings VT and CT ratios. (Two weeks)

7. Review metering compartment fabrication details prior to ordering equipment. (Two weeks)

8. Review plans for grounding of equipment. (Two weeks)

E. Initial Parallel Operation

Parallel operation will be permitted only after SRP has done the following:

1. Reviewed and accepted the required design documents, including the one-line meter and relay, elementary, plan view, elevation, and grounding drawings.

2. Inspected the completed installation including any transmission or distribution lines that will connect to SRP facilities.

November 17, 1999

Case for No Distributed Generation in the Utility Network System

Due to the network system reliability and safety issues as yet unresolved. I can not and will not in honest conscience condone the idea of Distributed Generation in the utility network system.

As I have been involved with the Distributed Generation Interconnections Committee for the purpose of insight. Having been and currently am an electric utility worker and at this time a foreman for Arizona Public Service with 27 years of electric utility experience. It is ludicrous to me and all fellow co-workers to even begin to embrace the idea of Distributed Generation in our current primary network systems. Due to relay functions there is no way to coordinate our network system with Distributive Generation. The issue of reverse power flow with the unloading of a network system causing outage problems have not at this time been resolved nor addressed earnestly with in our particular committee with very little time allocated to the resolution process.

Also to address the safety aspects, one needs to understand the volatile nature of our work. Especially in confined spaces and vaults where primary network systems exist in the utilities service territory. To have a problem with reverse power flow, and the subsequent opening of relays, dropping unintended load due to distributed generation can be catastrophic for any worker in these vaults or enclosures who may be pulling routine maintenance or addressing other issues when these events may occur.

When the concept of including Distributive Generation into the utility service company's primary network system, our original draft document deemed the idea intolerable. At this point one of the vendors on the Distributive Generation Interconnect workgroup admitted and properly stated that Distributive Generation was "unfriendly" to the concept of application to a primary network system. This was stated by a vendor and proponent of the idea of Distributive Generation into the network system. As a worker who is concerned about the proper attention given: 1. To safety of life, limb, or property. 2. The adherence and dedication to proper safety methods and procedures and, 3. The reliability of a system built with careful diligence and attention to detail. The attempt to apply an "unfriendly" concept leaves great concern for safety and safe practices. Dealing with the nature of primary voltage and the concept of applying an "unfriendly" entity is inconceivable.

Also during the Arizona Corporation Commission Distributive Generation and Interconnection Workgroup Meeting of October 25, 1999, in Phoenix, Arizona, the Business Case for the Virtual Power Plant was presented by Scott A Castelaz of ENCORP Vice President of Marketing and Corporate Development.

Post-it® Fax Note 7671	Date 11/18/99 # of pages ▶ 3
To Chuck DeCorse	From Jerry Smith
Co./Dept. TEP	Co. ACC
Phone # 1-520-628-6553	Phone # 1-602-542-7271
Fax # 1-520-628-6559	Fax # 1-602-542-2129

At a point in his presentation he mentioned that Manhattan was not involved in Distributive Generation. Mr. Castelaz further explained that he had attended several of the interconnection workgroup meetings. When questioned further, Mr. Castelaz admitted that SAFETY was the overriding factor in the decision to not have Distributive Generation involved in the network system of Manhattan.

This should be a revelation to anybody considering the planning of Distributive Generation into a primary network system. The safety and consideration of utility workers must be realized.

In closing I must be frank and honest. Therefore, I believe that the Arizona Corporation Commission facilitation process of our interconnections workgroup was flawed and inadequate. (i.e.) When our group first touched on Distributive Generation going into our utility network system it was completely evident that this was going to be a difficult issue for resolution to say the least. We were only allocated approximately two (2) hour's discussions on this subject. However, we were allotted days on the word smithing of the definitions section! When our group started the draft document we naturally started at the beginning of the document. To me this was the correct place to start. We reached the conclusion that the forward could be written at a later date. We then went to the second section, which is the scope and were provided with adequate time to word smith the scope section. After spending untold hours involving at least two days on section three (3) – definitions, we then progressed to section four (4) upon which we touched on Distributive Generation within the network system for approximately two hours. It was then decided to go to the back of the document and progress forward. After word smithing and making adjustments to sections 12, 11, 10, 9 not our committee, 8, and sections 7 which is a descriptive section, we were at a time frame of approximately 2:00 p.m. on November 15, 1999. It was then made known to us as a committee, that the time constraints were moved up to Monday, November 22, 1999, as opposed to the original time line of December 1, 1999. Still, with not enough time to begin to address Distributive Generation in Network. The only recourse was stated by Jerry Smith was to write a case of resolution to be addressed by a committee of select people within the three committees, 1) siting, permitting 2) access, metering and dispatch, and the interconnections committee.

I can only hope this was not by design. I strongly urge the Arizona Corporation Commission to put together a group of best minds to adequately address this giant issue of Distributive Generation in utility network system. This is given the careful consideration of safety, reliability, technical and contractual aspects a responsibility of this magnitude needs to be given.

If not important enough to give due consideration, I would strongly urge that the original draft and revision 1 stand as stated on page 6 under section 4 policy on Distributive Generation not be connected to a network system.

This case for resolution will be filed at our local and international levels for further reference. Hoping that no catastrophe or calamity occurs due to oversight or lack of reasonable research into this issue.

Sincerely,

I.B.E.W. LOCAL UNION NO. 387

Carl C. Brittain

DATE: NOV. 24, 1999

FROM: CARL C. BRITTAIN

SUBJECT: DISPATCH

Proper dispatch with all Distributive Generators identified through proper, and accurate mapping is not only imperative, it must be on absolute. Proper accurate and understandable dispatching will aid in the prevention of wasted motion of a crew or crews dispatched to a certain area. It can promote team work, and help undeniably in the prevention of accidents/incidents. Communication is one of our first lines of defenses against accidents. Proper geographic locations and identification of exactly what exists at any geographic location is therefore imperative. A direct correlation should be seen between accurate, timely mapping and the ability to properly dispatch.

Now in taking the idea of how to develop a proper dispatching scheme, one must first see what all of the UDC's use for radio language. What does SRP use? Do they use the signal method of communication? I.E. "Signal Seven" is "yes". "Signal 14" is "no", "Signal 13" is "any messages", "Signal 20" is "systems are back to normal." What UDC's use this method of terminology for dispatchable radio communication. APS uses this signal code. Do the CoOp's use this or the 10-4 method ? Some may even use CB radio communications.

To have proper dispatch in regard to the existence and acknowledgement of Distributive Generation, one must have one radio code to begin with. Then there has to be a bonding of an exact nature between dispatch/ mapping no matter who is to do either. Therefore, these two issues, I would urge be addressed together as they are needed to support one another.

A breakdown in communication has lead to many serious and fatal accidents with the utility industry. These two areas need to be addressed as to the extreme dependence utility crews must put on both. Dispatch, as to who has opened what, who has closed what, the communication of switching orders, clearance points, hold tags, places where working grounds are installed. This is an exact science, developed over many years within the Power industry. It is not at all a trivial part to be played in the Distributive Generation scheme and needs to have a thorough accurate, and realistic approach as to how dispatch is to be laid out between the UDC's, the Distributive Generators, and those to whom this grave responsibility will lie.

Sincerely,

Carl C Brittain

Carl C. Brittain

DATE: 11/23/99

MEMO TO : ACC DGI WORK GROUPS

FROM: CARL C. BRITTAIN IBEW 387

SUBJECT: TRAINING AND CERTIFICATION

NOV 29 1999

The added existence and possible for DG's existence mandates that adequate and comprehensive training, to include certification be employed. Up to the present day, the number of DG units involved in any particular UDC's territory has been minimal. Leaving the UDC's with a very manageable correspondence between the UDC' sand The DG's currently employed through out Arizona. However the more this phenomenon takes effect, the more units applied to any one UDC's system, naturally the less manageable and less looked at by a UDC this will become.

This is a cause of great concern, because Distributive Generation will allot any one wanting to export power on the UDC grid the opportunity to be a power producer. Having the ability, to do so, without any of the training that UDC's strived for and learned both through success, and unfortunately, failure. When we speak of failure in dealing with an entity known to us as generated power. We must speak in terms of human sacrifice. All of UDC's training, diligence and attention to detail have been scripted with the integrity of human safety at the forefront.

Therefore, I would urge any and all involved in the rule making process to understand and not underscore the training, and evolutionary process of training for certification at Distributive Generation Sites. This must be looked at with the level of expertise and dedication to detail that the UDC's and labor over the years have observed.

Therefore, I would like to point to a white paper written by Mr. Jim Corbin, (attached), President, IBEW local 1116 urging the consideration for training and certification be thoroughly reviewed and understood. Especially correlating this letter to size and location of existing and proposed DC unit, for the safety of all people involved and the reliability of the Distribution Grid.

Respectfully

Carl C Brittain

Carl C. Brittain

NOV 29 1999

Director of Utilities

DATE: September 14, 1999

MEMO TO: ACC DGI Work Groups

FROM: Jim Corbin
President, IBEW Local 1116
(502) 792-1475
270

SUBJECT: Training and Certification

We have been asked by the Siting, Certification and Permitting Committee to state our position on worker training and certification. Some of these issues may overlap with discussions in the Interconnection Standards Committee and consultation with those groups may be necessary.

Safe construction, maintenance, and operational practices in the Electric Utility industry are the key components to a safe and reliable electric supply. The United States has one of the most reliable and low cost electrical supply systems in the world. The key factor to our successful system has been the people that build, maintain and operate the Generation, Transmission, and Distribution segments of the industry.

Many of the jobs involved are extremely technical and hazardous and thus require a high level of training and expertise to prevent accidents to workers and the public and keep unplanned outages to commercial and residential customers at a minimum. For these reasons, a high level of skill and ability should be maintained by the incumbent utilities and required of any future participants to prevent degradation of our existing system.

For example, the training required to become a Journeyman Lineman/Cableman entails a State and Federally overseen four-year apprenticeship program. The curriculum includes a minimum of 144 hours of classroom time (math, electrical theory, National Electrical Safety Code) per year, and a minimum of 2000 hours in the field demonstrating competency in on-the-job training (pole climbing, proper connection practices, clearances and lock-out procedures.) If at any point during the apprenticeship the applicant fails to meet attendance, minimal test scores, or any on-the-job training requirements, they are removed from the program.

This enormous amount of training and responsibility is paralleled on the Generation side of the industry. On average, a six-year training program is required to become a Control Room operator, from starting as new operator to being able to operate the control panel unassisted.

Allowing untrained, uncertified, and unlicensed contractors to come into the State of Arizona to install and operate distributed generation that is connected to our electrical system is inviting disaster to the most critical element of our infrastructure. The customers of Arizona's electrical utilities deserve and should expect the people that bring power into their homes and businesses to be qualified and knowledgeable in all facets of safety and reliability. Because this very issue was overlooked in drafting distributed generation language in California, regulators and staff are presently trying to correct sub-standard construction practices by retroactively implementing minimum standards for workers and contractors. We should not make the same mistake. We need to have minimum standards of 160 hours classroom time per year and 2000 hours field related work for electricians that will be involved in electric construction work i.e distributive generation work, protecting our customers and our system from unqualified personnel before any damage can occur.

Possible language could require minimum hours for exposure to the National Electrical Code, OSHA training such as rescue procedures, traffic control, lockout/tagout, Personal Protective Equipment, medical and first aid, fall protection, fire fighting and prevention, drug and alcohol, noise exposure, and excavations.

Third party certification should be required from a state or federal agency, verifying training requirements and minimum standards have been met, as is currently being done with the apprenticeship programs.

Please contact our office at the above number if we can answer any questions or assist you in any way. Thank you for your interest in this important topic.

DATE: NOV. 23, 19999

MEMO TO: ACC DGI WORK GROUPS

FROM: CARL C. BRITTAIN IBEW 387

SUBJECT: ADEQUATE GROUNDING AT DISTRIBUTIVE GENERATION SITES

While sitting on the interconnections committee for Distributive Generation, I posed a question relating to the adequate grounding of Distributive Generation sites. In particular, those Distributive Generators involved in parallel operation with a UDC and exporting power at the primary level.

Now, with this in mind, I know that APS specifications on the ground grid at substations is (.25 of one OHM) of resistance. Having stated this very important specification, we now need to address what type, and at what tolerance of resistance, can be acceptably applied on Distributive Generation in parallel operation with a UDC and involved in the exportation of power at primary levels.

There must be a very rigid and concise specification for Distributive generation, because of the availability of compiled fault current. I.E. the UDC's available fault current, not to mention the possible aggregation of D. G. 's on the same circuit. If these Distributive Generators do not have an adequate ground grid or scheme when a problem arises, then all the generation available, operating in parallel will see this fault as load and continue contributing fault current to the DG in question.

This will subsequently create a severe safety dilemma, possibly causing step touch catastrophe and gradient fault current at the affected site. Therefore, it is imperative that a sound level of acceptable OHMS of resistance be mandated and verified at all DG sites wanting to operate in parallel and export primary on the UDC grid

Sincerely,

Carl C Brittain

Carl D Brittain
IBEW Local 387
Phoenix AZ

RECEIVED
NOV 29 1999
Director of Utilities

DATE: NOV. 23, 1999

FROM: CARL C. BRITTAIN

SUBJECT: TIME FRAME AND ASSURANCE OF PROPER MAPPING OF DISTRIBUTIVE GENERATION

The ASSURANCE that every Distributive Generator, especially those involved in the exporting of power can not be overstated. The fact is that utility crews will have to deal with the concept of multi-sourced primary, by the very nature of DG and its planned application in the future. It therefore is imperative that absolute and timely control be exercised regarding the accurate mapping of DG.

On page 9 of the Nov. 22, 1999 "Siting, Certification, and Permitting" Committee Report states that a discussion was held as to who will keep and update maps of all DG units as they are installed. It further discusses a proposal made that the ACC could update and maintain such a map at their Web Site. The ACC is not favorable to this position The UDC's currently update their maps showing DG units on their system. This is done with relatively few DG's in existence on any UDC's territory.

As a worker involved in the maintenance emergency repairs and basic upkeep of the Distribution Grid, I find this hard to swallow. The fact that DG's can and, if certain parties have their way, will pop up through out our systems, it is imperative that a TIME STAMP be mandated as to when a DG goes on line and it's subsequent accurate mapping. This must be done as expeditiously as possible. This is needed for a number of reasons: 1) Utility crews must have the availability to pick up a viable hold tag. In order to accomplish this all Distributive Generation on the circuit must be isolated from the grid. This is to assure the crew that in the unfortunate event the hold tag is used i.e. that some type of disruptive event occurred causing instantaneous lock out of the circuit, no unmapped Distributive Generation the crew would have isolated from the grid, remains on the grid and continues to provide power or fault current to the location at which the utility crew is performing its work. 2.) For the purpose of establishing clearance points, i.e. a point at which all know sources of power are removed and will remain that way until work is complete. In the case of a major storm or dilemma in which a large portion of line or lines is down. Clearance points can be moved to another geographical location as restoration work is completed. There by allowing for the reinstallation of DG on what has been restored. With the remainder to be isolated from the grid until, again, utility clearance points may be moved. Therefore, DG has to be correctly, accurately, verifiably mapped to insure the DG can at the right time be reinstalled on the grid. Proper, timely mapping of DG will help assure clearance points an hold tags are accurate and defined so as not to allow unwanted primary voltage on any piece of line or equipment.

Also regarding the idea as stated in the second paragraph second line of page 9 " it has been suggested that these maps could be made public" is unequivocally ludicrous. I don't believe I need to point out the time in which we live. To have these type of maps of Distributive Generation easily accessible to the public could invite terrorism on the total Distribution Grid. I do not feel this needs any more clarification.

One other point I need to reiterate is the fact the ACC is not favorable to the position of updating and maintaining such maps on their web site. I applaud this stance, because mapping and updating on the ACC web site is not going to be beneficial to myself or or any of my co-workers whose life and lives depend on the proper mapping of DG on the distribution Grid. We do not have access to the ACC web site on any particular job.

As a point to be made concerning the idea of mapping at the ACC web site is that this web site is not going to be of any help to any utility crew or troubleman at say, 2:35AM on any given morning with trouble shooting in general, or making repairs in an alley or avenue in downtown Phoenix, in the Mountainous area throughout the state or in the middle of the desert, trying to figure out exactly what is in existence as far as DG on any piece of line or equipment anywhere with the distribution grid of the Sate of Arizona can not be speculative, mapping must have a TIME STAMP.

I hope that a proper plan is developed, carefully constructed and thoroughly over viewed, as to time frame , accuracy and accountability of the mapping of DG. This will also directly relate to dispatching of maintenance, repair, and general up keep again, not forgetting trouble shooting and proper dispatch.

Submitted Carl C Brittain
Carl C. Brittain

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AZ CORP COMMISSION
DOCUMENT CONTROL

Arizona Corporation Commission
Distributed Generation and Interconnections Workgroup

ACCESS, METERING & DISPATCH COMMITTEE FINAL REPORT

December 15, 1999

EXECUTIVE SUMMARY

Objectives

As part of the overall ACC workgroup formed to investigate issues concerning distributed generation ("DG"), the Access, Metering, and Dispatch Committee ("Committee") was asked to

a. Assess the potential impacts of DG on the planning and operation of the utility distribution grid. and

b. Explore tariff, pricing, contract, and other business arrangements needed to facilitate the installation of DG.

Process

The Committee was represented by a variety of stakeholders of distributed generation including, the ACC Staff, RUCO, utilities ("UDCs"), competitive energy service providers, equipment manufacturers, distributors, contractors and other interested parties ("DG Providers").

The Committee discussed the issues, attempted to understand the concerns of other parties, and to reach a general understanding of the issues and potential solutions. However, the Committee did not strive to reach consensus on each issue or to vote for a particular policy recommendation. Instead, the Committee's goal was to educate the Commission and other interested parties about the key issues, and to articulate the concerns and viewpoints of the various stakeholders.

Background

While most of the UDCs are beginning to assess, test and pilot DG applications, the overall experience with DG in Arizona is low. Most UDCs report only a few existing customer DG installations, typically back-up emergency generators or small QF facilities.

Key Issues

1. Many of the potential impacts on the UDC distribution system will depend on several factors including the size of the DG or aggregate DGs relative to the size of the relevant distribution circuit, the location of the DG on the system, whether the DG is connected to the grid, and whether the DG is selling power back over the grid, the

Arizona Corporation Commission
Distributed Generation and Interconnections Workgroup

ACCESS, METERING & DISPATCH COMMITTEE
Final report

December 15, 1999

Executive Summary

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1. Many of the potential impacts on the UDC distribution system will depend on several factors including the size of the DG or aggregate DGs relative to the size of the relevant distribution circuit, the location of the DG on the system, whether the DG is connected to the grid, and whether the DG is selling power back over the grid, the timing of DG installations, and the

7. UDCs emphasized that the under the current direct access tariff structure, the rates charged a direct access DG owner for any supplemental, backup, and/or maintenance power delivered are based on full requirements service. The installation of DG reduces the number of hours (or load factor) the distribution system is being used by a specific customer and reduces the amount of revenues collected by the distribution UDC under the provisions of the applicable direct access tariff. DG Providers stress that backup rates should be fair and reasonable and based solely on those costs actually incurred by the distribution UDC to provide the specific service. The rates should not act as a disincentive to the deployment and use of DG by customers nor should it be a direct subsidy for DG owners/operators. Again, SRP has approached backup power through a single set of unbundled tariffs, rather than separate standard offer and direct access rates.

8. The Committee concurs that UDCs should not be required to buyback excess generation from DG from either standard offer or direct access customers, except as required under existing PURPA rules. However, at their option, UDCs could elect to offer a DG buyback service as part of a standard offer service, with requirements, restrictions, and limits as determined by the distribution UDC. The Committee also believes that UDCs could also (at their option) buyback excess DG power from direct-access customers, as part of their generation procurement process.

9. The Committee believes that under the current Competition Rules, DG owners cannot sell excess power to other retail customers unless they become a licensed ESP or sell to an ESP. The legal requirements for such sales are currently being debated in other jurisdictions and are being reviewed by the legal staffs of Committee members. At this time no definitive conclusion has been reached, therefore, the Committee recommends additional follow-up on this issue. DG Providers further recommend that the current ACC rules should be reviewed to determine if modifications are necessary to allow sales of excess power to others, such as the distribution UDC or entities or properties under common ownership and/or control that are non-contiguous. The modifications may be necessary to allow increased customer choice and greater competition.

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Arizona Corporation Commission
Distributed Generation and Interconnections Workgroup

ACCESS, METERING & DISPATCH COMMITTEE
Final report

December 15, 1999

I. Introduction

A. Objectives

1. As part of the overall ACC workgroup formed to investigate issues concerning distributed generation, the Access, Metering, and Dispatch Committee ("Committee") to:

    a. Develop a framework for distributed generator customers accessing the energy market to acquire supplemental power, sell excess power to others, and contribute to ancillary services.

    b. Identify a means of accurately scheduling and accounting for the related transactions to protect system constraints.

    c. Develop an operating protocol to efficiently manage system disturbances in the presence of distributed generation.

    d. Identify technical requirements associated with these functions.

    e. Identify conditions where system benefits or stranded cost may result, that warrant pricing consideration.

    f. Develop tariff concepts that facilitate the above transactions in a consistent and equitable fashion.

G. Participants

1. The Committee was represented by a variety of stakeholders of distributed generation including, the ACC Staff, RUCO, utilities, competitive energy service providers, equipment manufacturers, distributors, contractors and other interested parties.

2. A list of participants is provided in Appendix B.

C. Definitions and Abbreviations

1. Distributed Generation ("DG"). The Committee did not develop a formal definition of DG. We recognized that DG equipment and applications could be very broad, from very large units attached at to transmission grid and selling excess power over the system, to very small generators for loads completely separated from the utility. However, for the purposes of assessing potential impacts to the utility distribution grid and policies for back-up and buy-back tariffs and other issues, we generally considered DG to mean generation placed on a customer's site or close to a load center, and smaller than the traditional merchant plants, which sell into the wholesale market.

2. Utility Distribution Company ("UDC"). The wires portion of a traditional vertically integrated utility, which is accountable for managing the distribution grid, managing the transmission grid in coordination with the ISA or ISO, and procuring power for standard offer service.

3. Energy Service Providers ("ESPs"). Competitive providers of energy services including generation, aggregation, billing, and metering.

4. DG Providers. Parties involved in implementing DG projects including ESPs, Gas suppliers, DG manufacturers, contractors, and customers purchasing DG equipment.

5. Direct Access Customers ("DA"). Customers purchasing competitive energy services from an ESP at market prices.

6. Standard Offer Customers. Customers purchasing traditional bundled energy services from the UDC at regulated tariffs.

7. Arizona Public Service ("APS"), Salt River Project ("SRP"), Tucson Electric Power ("TEP").

H. Approach and Report Organization

1. The Committee formed two subgroups to analyze (1) operation and UDC planning issues and (2) tariff and policy considerations.

2. In addition to the regular Committee meetings, the Committee met with the planning and operation staff of APS, SRP, and TEP to investigate the issues discussed in this report.

3. The report first addresses the potential impact of DG on the distribution grid, next it discussed potential remedies to these impacts, and lastly, it reviews various tariff and policy issues.

4. The Committee discussed the issues, attempted to understand the concerns of other parties, and to reach a general understanding of the issues and potential solutions. However, the Committee did not strive to reach consensus on each issue or to vote for a particular policy

recommendation. Instead, the Committee's goal was to educate the Commission and other interested parties about the key issues, and to articulate the concerns and viewpoints of the various stakeholders.

4. Shareholder concerns are often labeled in the report as the viewpoints of UDCs and DG Providers. Please be advised that those are general statements; not all of the UDCs or DG Providers agree with all of the views expressed by their represented group.

V. Potential Impacts of DG on the Planning and Operation of the UDC Distribution Grid

A. Overview

1. The potential effects of DG on the planning and operations of the UDC distribution grid were discussed within the Committee and also assessed with a broader group of transmission and distribution planning and operations personnel from APS, SRP, and TEP. While most of the UDCs are beginning to assess, test and pilot DG applications, the overall experience with DG in Arizona is low. Most UDCs report only a few existing customer DG installations, typically back-up emergency generators or small QF facilities.

2. Many of the potential impacts on the UDC distribution system depend on several factors including the size of the DG or aggregate DGs relative to the size of the relevant distribution circuit, the location of the DG on the system, whether the DG is connected to the grid, and whether the DG is selling power back over the grid, the timing of DG installations, the operating characteristics, and hours of operation.

3. Given this, the Committee assessed the planning and operational issues for four scenarios: (1) the DG is separate from the grid, (2) the DG is grid connected, but is not putting excess power back on the grid, (3) the DG is selling excess power over the grid and (4) the DG or aggregate DGs reach certain size thresholds. For each of these applications, the Committee assessed the potential impacts on the grid operations and design, scheduling, information, and metering needs, and the potential for dispatching the DG unit.

4. Below is a brief summary of the issues for each of these factors.

DG Applications and Issues

Application	Potential Operation and Design Impacts	Scheduling, Information, metering Needs	Dispatch, Automation
Separate			

Grid Connected			
Sell back			
Size			

E. Application 1: DG is Separate from Grid

1. Description
   a. DG is not connected to the grid;
   b. Typically used as emergency backup;
   c. Can be used for peak-shaving or other operation
   d. Customer load could be connected to, or separate from the grid and able to reconnect through a transfer switch.

5. Distribution Operation and Design Impacts
   a. For emergency back-up applications, there would be low or no impacts on the design and operation of the distribution grid.

   b. UDCs could call upon emergency generation to be run to off load customers load during high peak times.

   c. For peak-shaving applications, if DG goes down and load is not separated from grid, then the grid will have to pick up the load. If distribution facilities were designed to accommodate the total customer load, absent the peak shaving, then this impact becomes more of a cost recovery issue, rather than a design issue.

   d. Adding baseload DG to an existing customer could cause load to drop below minimum level for a feeder, which could result in voltage regulation issues. This could be a design issue if the DG is a significant size relative to the circuit. (This is discussed below under size criteria section.)

5. Scheduling, Information, Metering
   a. If a DG used for emergency backup fails, the grid would have to pick up the load during an emergency situation. Therefore Mapping of DG locations may be important because they may impact emergency feeder switching practices.

   b. No additional metering requirements for this scenario.

3. Dispatch, Automation
   a. Emergency, Backup DG applications could be strategically run to reduce load during UDC peak periods.

C. Application 2: DG is Grid Connected, but not Selling Excess Power over the Grid

1. Description
   a. DG is connected to the grid;

   b. Customer may be purchasing power from the grid and self generating the rest.

   c. Customer is using DG for own site load, no power is intentionally being delivered or sold back to the grid.
   d. Could be used for a variety of applications including emergency, baseload, cogeneration, and peak-shaving.

5. Potential Distribution Operation and Design Impacts
   a. Potential for load to lean on grid if DG goes down.

   b. Same issues under "Separate" case.

   c. Switching requirements

4. Scheduling, Information, Metering
   a. Some emergency applications run parallel when a storm is eminent to protect continuity of supply; they notify the UDC by phone. Another notification system may be needed if the number of such applications increases significantly.

   b. May also need to map locations for same issue discussed under "Separate" case.

3. Dispatch, Automation
   a. Could dispatch or incent DG to run and reduce load during grid emergencies.

D. Application 3: DG is Selling Excess Power over the Grid

1. Description
   a. DG is connected to the grid;

   b. Customer is selling power back to the grid or transporting power over the grid for use on another site.

   c. Could be used for a variety of applications including emergency, baseload, cogeneration, and peak-shaving.

4. Potential Distribution Operation and Design Impacts
   a. UDCs were concerned that the CAO typically addresses transmission issues; distribution transactions may not be adequately considered.

b. UDCs may need to know additional information, on top of the ESP schedule, on where the load is being put on the system, especially above a size threshold.

3. Scheduling, Information, Metering
   a. Sales would typically have to be made to the UDC or to an ESP.

   b. Grid sales to ESPs, above a certain size, would typically to be included in an ESPs schedule.

   c. Sales to grid should be metered through an interval meter, at least above a size threshold. UDC metering could be accomplished through several techniques, which are described below in the Metering section under Tariffs and Policy.

4. Dispatch, Automation
   e. Could dispatch or incent DG to run and reduce load during grid emergencies.

F. Application 4: Size of DG

1. Description
   a. The committee discussed a variety of size demarcations for DG, which could determine the potential impacts on the distribution grid. The size categories were somewhat arbitrary, however, the Committee generally divided discussions into the following bins:
      - 0 - 300 kW
      - 300 kW - 1 MW
- 1 MW - 10 MW
- Above 10 MW

5. Potential Distribution. Operation and Design Impacts
   a. The size impact depends on several other factors: the capacity of the distribution circuit, proximity to UDC generation source e.g. substation and whether the customer is served from a radial circuit, transfer switch, or spot network.

   b. The size issue also depends on the size of the DG relative to customer's service.

   c. The DG impact also depends on the operating hours of the DG relative to daily and seasonal peak of the feeder.

   d. DG applications above 10 MW would typically be connected to the transmission grid, not the distribution grid. These applications would require individual project coordination with the UDC, including grid impact studies and other informational needs. Given the customized nature of this category, it was not assessed in detail by the Committee.

e. UDCs were concerned about DG applications above 1 MW, connected to the distribution grid. The capacity for most distribution circuits are in the 5 - 10 MW range, therefore, DGs above 1 MW can be significant relative to size of the circuit. These units could affect the operational issues discussed above, such as feeder capacity, emergency or seasonal switching, and minimum voltage issues.

f. In general, the UDCs had a lower level of concern for the 0-300 kW DG applications from a planning or operational perspective. The concern would increase, however, if multiple, small DGs were added to the same circuit, so that the aggregate generation became substantial.

g. There was mixed discussion concerning DG applications in the 300 kW - 1 MW range. UDCs expressed that there could be situations where DGs in this range could be a concern for distribution planning and operations. These potential impacts would depend on the factors discussed herein. DG Providers expressed that units in this size range should be a lower concern for UDCs. Furthermore, the potential impacts would be similar to many existing customer issues such as customers increasing or reducing load either permanently or intermittently.

8. Scheduling, Information, Metering

a. Sales would typically have to be made to the UDC or to an ESP.

b. Grid sales to ESPs, above a certain size, would typically to be included in an ESPs schedule.

c. Sales to grid should be metered through an interval meter, at least above a size threshold. UDC metering could be accomplished through several techniques, which are described below in the Metering section under Tariffs and Policy.

4. Dispatch, Automation

a. Could dispatch or incent DG to run and reduce load during grid emergencies.

B. Potential Remedies for UDC Distribution Planning

1. General Concerns

a. UDCs are generally concerned that grid design and operation issues are adequately addressed as more DG units are installed and DG excess power is transmitted onto the distribution system. In this section UDCs discuss possible solutions to address the concerns described above.

b. DG providers are concerned that UDCs planning processes adequately accommodate DG installations and that they are (1) forward looking, (2) streamlined, (3) reasonable and fair, and (4) not unduly costly to DG projects.

b. One of the DG Providers felt strongly that DG should not impose a substantial threat to distribution system planning in the near term and was generally concerned that new rules imposed by the ACC could adversely is impact the implementation of DG in Arizona. They felt that the restructuring of the electric industry and changes in technology and safety requirements all affect distribution system planning. Although distribution system planning, by the distribution UDC, could be impacted by significant penetration of DG units on the specific UDC's system, this is not expected to occur in the near term. Distribution system planning should not be adversely affected by the addition of a relatively small number of small DG units dispersed throughout the distribution system. The addition of DG to the mix of factors that distribution system planners must be cognizant of, should not be used as a basis to erect barriers to deployment of DG and customer choice and should not be construed as a basis to impose higher costs on DG owners/operators.

3. Rules of Thumb

a. The Committee discussed two possible rules of thumb to determine when DGs would be considered substantial relative to the capacity of a feeder and, therefore, would require increased information and design considerations by the UDCs.

- A single unit DG would be considered substantial if its capacity were over 50% of the feeder capacity. Aggregate DG capacity on the same feeder could go above this level before being considered substantial due to the diversity of the units.

- Aggregate DGs would be considered substantial if they caused existing loads to drop below minimum load level for a feeder.

c. While, these rules of thumb generally seemed reasonable, the UDCs expressed concern about adopting them as policy decisions. Their concerns were twofold. First, there is uncertainty on the potential grid impacts from DG, and second, there could be important exceptions where these rules of thumb would not be prudent for a particular feeder.

4. When does DG Impose a Substantial Impact to the Grid?

a. Below, the UDCs describe potential planning actions that could be taken to address the DG concerns. This discussion is relevant to (1) DG units attached to the distribution grid and (2) for "substantial" potential impacts. The UDCs have recognized that the potential impacts of DG increase with larger DG units, or with the number of units on a circuit. The point at which the DG comprises a "substantial" share of circuit capacity is still an open question.

4. UDC Potential Planning Remedies

a. While the Committee is not recommending specific planning requirements at this time, the UDCs have generally explored potential actions that could be taken to address the various concerns. The UDCs generally describe their planning process and potential impacts from DG as follows. Using a detailed criterion, the distribution system planning process is used to identify capital improvements that are necessary to maintain high quality, reliable, and safe electric service to our customers. The purpose of this section is to identify possible changes to the current distribution planning process precipitated by the addition of substantial amounts of DG to the UDC grid, assuming that most new generating facilities are distributed on the UDC grid in relatively small units.

b. Facility Loading (transformers, wires, and, switches)

1) With substantial amounts of DG connected to the system, facility loading would be determined by adding each DG unit (watt and var output) to a computer model.

2) Two separate cases would probably need to be run (all DG off-line and all DG on-line). In the "all DG off-line" case, we would still be required to supply the feeder load. Since we will still supply the total load, the DG owners should be required to pay for this reserve capacity.

3) There would be no way of verifying the load flows because there is only one metering point at the substation bus. If this became significant it could be mitigated by adding telemetry to the significant DG facilities.

4) It is important to keep the "permitting" time short for new DG installations. This may cause a problem if there isn't enough time to adequately study the different system configurations.

e. Voltage profiles (from the substation to the end-of-line)

1) Voltage planning is required for the "peak" load case as well as the "minimum" load case since we have HIGH voltage and LOW voltage targets. The "all DG off-line" case would be used to determine the feeder voltage profile during the "peak" load condition. The "all DG on-line" case would be run during the "minimum" load condition.

2) Voltage control would be complicated because we would not be scheduling the DG units. If it became significant, The UDC could partner with the customer and allow the UDC to use the unit to improve voltage regulation.

3) The Distribution UDC would still be required to provide Power Factor correction for the "all DG off-line" case. DG owners should be required to pay for this reserve capacity.

d. System protection (breakers, reclosers, sectionalizers, and fuses)

1) Depending on the size and location of the DG unit, the distributed generator may back feed through a protective device causing a misoperation. Larger size DG units may add to the system available fault current thereby exceeding the ratings of existing devices. In addition, larger DG units would require "inrush" analysis to limit short-term voltage dip to other customers. All these conditions can be mitigated with the appropriate added system analysis.

b. Contingency planning (load transfers)

1) Equipment failures, storms, dig-ins, and accidents typically cause most outages on the system. There would be no reduction in the frequency of outages as a result of DG additions to the system. In addition, the outage duration may be increased because repair time will be increased. In order to make repairs; the operations personnel will need to verify that no sources remain connected to the system. This must be done by observing a "visible" open switch.

2) The most difficult problem facing the operations personnel will be the feeder load transfer operation. When a block of load is to be moved from one feeder to another feeder all the above mentioned concerns must be addressed by field personnel.

3) The following questions will need to be answered by field personnel and/or engineering staff concerning any distributed generators:

- Will the distributed generators be "on" or "off"?
- What is the true load to be picked up by the secondary feeder?
- How is the protection scheme effected?

4) The engineering staff can answer these questions after the appropriate analysis. But these questions will not be answered by the field personnel at 7:00 P.M. on a Saturday Evening during a summer windstorm.

5) The current distribution system is a simple radial system. The addition of DG to the current distribution system in effect creates a quasi-looped system. The transmission system is a looped system and as such requires ten times the amount of computer analysis as a radial system. Looped systems require a more complex computer program and require that all contingencies (load transfers) be modeled. In other words, the installation of DG increases the level of complexity of the distribution system tenfold while at the same limiting control of the system components (DG).

6) If larger DG units are installed and controlled by UDCs at strategic locations,

many of the planning issues can be minimized or eliminated.

F. Potential Benefits of Dg to the Grid

1. The Committee discussed potential benefits that DG could provide to the distribution grid. These include voltage support, reliability, lower losses, power quality improvements, and potential deferral or avoidance of UDC distribution investments. These issues have been explored in significant detail in other industry publications and, therefore, the Committee did not go beyond a general discussion.

2. The UDCs emphasized that these benefits were potential and not yet proven. Many of the benefits could be on the customer's side of the meter, some could be on the UDC side. However, UDC benefits would likely be very specific to each DG installation. Furthermore, any UDC cost avoidance or deferral would also be case specific, and would have to coincide with the timing and location of load growth on the system. This is discussed further in the Policy section below.

3. DG Providers opined that the UDCs should be actively looking for these types of benefits, whether the DG is owned by the utility, owned by the customer and "dispatched" by the UDC, or owned by the customer and incented by the UDC to operate in such a manner as to provide benefits to the grid.

IV. Tariff and Policy Issues

A. Backup Service for DG

1. The Committee generally envisions that under the new world of retail competition, the UDC would provide backup service for standard offer customers, through a bundled generation, transmission, and distribution tariff. Direct access customers would obtain backup generation service from a competitive energy service provider ESP, through competitive prices. The direct access customer would also acquire UDC-provided distribution and transmission services for the backup power, either through general direct access tariffs, or partial requirements direct access tariffs.

2. The Committee believes that under the current Competitive Rules, the UDC would not have an obligation or opportunity to provide backup generation service to direct access service. This is because standard offer service is defined as a bundled service. However, some DG Providers felt that the Competitive Rules most likely did not fully contemplate the policies concerning DG, and that it could make sense to change the Rules to allow UDCs the opportunity (but not the obligation) to provide backup generation service to direct access customers.

C. Tariffs for Standby, Maintenance, and Supplemental Power

1. Standard Offer Partial Requirements Service for DG – APS & TEP

   a. The UDCs believe that if the DG owner chooses to be a standard offer customer, the distribution UDC is obligated to provide back-up, maintenance, and supplemental power under the provisions of a partial requirements tariff. APS already has these types of rates and related provisions in place. These rates would be applicable to any residential or non-residential customer requiring partial requirements services (DG). TEP has such rates in place for Qualifying Facilities (QFs) only. TEP has also designed and received ACC approval for a rate applicable to a small commercial, non-QF customer using DG in parallel with the UDC. TEP plans to model rates for other customers using DG after this initial rate.

   b. The economics of partial requirements tariffs (both existing and proposed) will need to be addressed to ensure that the rates appropriately recover the costs, including transmission and distribution (T&D) costs, associated with providing bundled partial requirements electric service to the DG customer.

   c. DG Providers suggested that the existing partial requirements tariffs were developed under the "bundled regime" of the past. These tariffs should be reviewed and revised, where appropriate, to ensure conformance with an "unbundled" world. Only the actual costs associated with providing the requested partial requirements service should be considered in developing the tariffs. Furthermore, the rates should not act as a disincentive to the deployment and utilization of DG by customers.

4. DG Owners Choosing Direct Access – APS & TEP

   a. As stated above, the Committee believes that the Competition Rules do not allow a UDC to offer back-up, maintenance, and supplemental power to DG owners choosing direct access. They must contract for these competitive direct access services with a certified ESP.

   b. The current direct access tariffs do not specifically address distribution delivery service to partial requirements (DG) customers.

   c. UDCs emphasized that the under the current direct access tariff structure, the rates charged a direct access DG owner for any supplemental, backup, and/or maintenance power delivered are based on full requirements service. The installation of DG reduces the number of hours (or load factor) the distribution system is being used by a specific customer and reduces the amount of revenues collected by the distribution UDC under the provisions of the applicable direct access tariff.

   d. UDCs added that partial requirements direct access rate should be designed to properly recover T&D and any other relevant plant investment from customers utilizing DG, because current direct access service is priced using demand and energy charges.

d. DG Providers argued that the number of hours the distribution system is used by a DG owner/operator is not necessarily reduced. DG used solely as back-up or as emergency generation would not reduce the number of hours the distribution system is used by that customer. Additionally, if DG is installed by the customer to meet new or increased load, the number of hours the distribution system is being used would not be affected. The use of DG for peak shaving purposes, although reducing the volume of kilowatt-hours and kilowatts flowing over the distribution system, would not reduce the number of hours the distribution system is used, and this application could also provide tangible system benefits to the distribution UDC.

e. Furthermore, DG providers opined that there may not be a revenue deficiency. Absent significant market penetration by DG in a particular distribution UDC's service area, a revenue deficiency may be insignificant and could potentially, over time, be offset by revenues from distribution system load growth from new customers.

f. The rate should be fair and reasonable and based solely on those costs actually incurred by the distribution UDC to provide the specific service. The rates developed should not act as a disincentive to the deployment and use of DG by customers nor should it be a direct subsidy for DG owners/operators.

g. Some DG providers believe that a partial requirements, direct access tariff may not be necessary. The existing direct access tariffs could be used and any UDC distribution company revenue deficiency associated with the installation of DG could be recovered through the existing direct access rate structure. However, according to the UDCs, this implies that any revenue shortfalls will need to be recovered from other customers after rates are adjusted in a subsequent rate case. To ensure proper revenue recovery, the existing rate design will need to be modified to recover distribution system costs through customer charges, contract demand charges, and/or ratcheted demand charges instead of the current commodity based kWh charges.

8. Single Tariff For Standard Offer and Direct Access Rates – SRP

a. SRP has a single set of unbundled tariffs, rather than separate standard offer and direct access rates.

b. SRP provides standby (partial requirements) service to large commercial and industrial customers served on the E-60 series price plans (over 1 MW and 300,000 kWh annually) under provisions of the standby electric service rider. The standby service rider applies to customers receiving electric service from SRP or an ESP. Unlike the Affected UDCs, SRP may provide generation service to direct access customers.

c. The rate design of the E-60 series price plans with the standby service rider is intended to appropriately recover fixed costs from all customers based on cost of service, not just customers with DG. Rate designs may be examined and modified by SRP in future rate adjustments, but SRP would not likely decrease the level of fixed cost recovery in any future rate design change, unless such a change is supported by actual cost changes.

c. SRP does not have a tariff or rider to provide partial requirements service to residential or small business customers. If the market penetration of DG becomes significant within these rate classes, SRP may consider developing an appropriate tariff or rider.

d. DG Providers suggest that customer choice and competition would be enhanced by the development of a tariff or rider for partial requirements firm or interruptible service to the residential and small commercial rate classes.

E. Selling Excess Power from DG to UDCs

1. General Obligations and Options

a. The Committee concurred that UDCs should not be required to buyback excess generation from DG from either standard offer or direct access customers, except as required under existing PURPA rules. However, at their option, UDCs could elect to offer a DG buyback service as part of a standard offer service, with requirements, restrictions, and limits as determined by the distribution UDC. The Committee also believes that UDCs could also (at their option) buyback excess DG power from direct access customers, as part of their generation procurement process.

b. UDCs suggested that under the current ACC competition rules and the APS settlement agreement, the UDC will eventually be required to purchase generation for its standard offer customer through a competitive bidding process. To obligate a UDC to purchase surplus power from a DG would be detrimental to a competitive market and could increase costs to other Standard Offer customers.

c. DG Providers agreed that the buyback of excess power from DGs should not, in general, be made mandatory. However, this assumes effective competition is present such that an ESP or other provider can and will contract with DG owners/operators to purchase their excess power. Absent effective competition, the ACC may need to review this provision. If the purchase of excess power from DGs is solely at the discretion/election UDCs, the ACC should emphasize and monitor that the UDC fairly includes DG power when it competitively procures power for standard offer service.

d. The election by the UDC to offer a DG buyback service should be based on requirements, restrictions, and limits as determined jointly by the DG owner/operator and the distribution UDC based on current market conditions.

e. DG Providers also commented that the DG should be considered as part of the portfolio of supply side resources and distribution UDC purchases of DG should be subject to the competitive bidding process. For the competitive market to function efficiently, the distribution generation owner, as a seller to the market, should participate in the competitive bid process if they wish to sell excess or "merchant" power.

5. UDC Tariffs

a. Buy-back Tariffs for QF

1) UDCs currently have standard offer purchase rates for qualified cogeneration facilities, qualified small power production facilities, qualified solar\photovoltaic facilities, and facilities utilizing renewable resources. Distributed generators meeting the requirements of a "qualified facility" under the provisions of the existing tariffs will be able to sell excess power to the distribution UDC under the provisions of these tariffs.

2) DG Providers argue that the existing QF buyback tariffs were developed under the "bundled regime" of the past. These tariffs should be reviewed and revised, where appropriate, to ensure conformance with an "unbundled" world.

3) TEP intends to modify its buy-back rates to be more consistent with market principles. Such buy-back rates will also be more easily adjustable to market prices, e.g., perhaps adjusted monthly or quarterly. In addition, TEP does not intent to continue to offer long-term buy-back contracts.

4) SRP intends to purchase power from residential, commercial, or large industrial cogeneration and small power production customers under the provisions of the Buyback Service Rider. The buyback credit is indexed to the day-ahead hourly California PX prices for Palo Verde delivery less $0.00017/kWh, which is the cost to provide scheduling, system control, and dispatch services under SRP's retail Open Access Transmission Tariff.

e. Buy-back provisions for Non-QF DG power

1) In general, the UDCs believed that voluntary buyback of DG by UDCs should be priced at the lower of the distribution UDCs short-run avoided cost or the hourly market rate. However, in the near future, the UDC's current calculation of avoided cost will need to be based on market prices instead of the current methodology which is based on the UDC's own production costs.

2) DG Providers suggest that the buyback of excess power from distributed generators should be priced at a competitive market rate or as established by contractual agreement between the DG owner/operator and the distribution UDC.

c. Firm Vs. Non-firm Power

1) UDCs maintain that excess DG power cannot be considered firm power and may

be supplied to the distribution grid at any time. This excess DG is unscheduled and could be detrimental to the current loading on generation plants as well as transmission and distribution facilities. This affects the value of excess DG to the distribution UDC on an hourly basis.

1) DG Providers assert that excess DG power may or may not be considered firm power depending on any contractual arrangement between the DG owner/operator and the distribution UDC.

D. Selling Excess DG in the Open Market

1. General Obligations and Options

a. The Committee believes that under the current Competition Rules, DG owners cannot sell excess power to other retail customers unless they become a licensed ESP or sell to an ESP. The legal requirements for such sales are currently being debated in other jurisdictions and are being reviewed by the legal staffs of Committee members. At this time no definitive conclusion has been reached, therefore, the Committee recommends additional follow-up on this issue.

b. DG Providers commented that the current ACC rules should be reviewed to determine if modifications are necessary to allow sales of excess power to others, such as the distribution UDC or entities or properties under common ownership and/or control that are non-contiguous. The modifications may be necessary to allow increased customer choice and greater competition.

3. FERC Requirements

1. The FERC classification and requirements for DG sales of excess power to an ESP or to another customer are currently being debated in several jurisdictions. Some Committee members have performed an initial review and opinion of this issue. However, the Committee recommends that the ACC continue to resolve this issue. Below is a summary of preliminary opinions by UDCs and DG Providers. Please note that not all UDCs and DG Providers necessarily share these opinions.

2. DG sales to an ESP (UDC Viewpoint)

1) In accordance with Section 201 (d) of the Federal Power Act the sale of electric energy at wholesale is defined as:

"a sale of electric energy to any person for resale."

2) DG sales to an ESP is considered a wholesale transaction subject to FERC jurisdiction. The DG owner would need a market rate tariff (filed with FERC) to sell excess generation to an ESP.

3) OATT charges apply for all sales of excess power from the DG owner to an ESP. ESPs will pay transmission charges even if the ESP elects to sell excess DG to customers located on the same substation or feeder as the DG unit from which energy is purchased.

4) If an ESP elects to purchase power from the distributed generator, an applicable FERC jurisdiction direct assignment charge for the distribution wheeling will apply. In order for the appropriate wheeling charge to be determined a direct assignment study will need to be done (in accordance with the provisions of the current OATT).

5) DG sales to an ESP (Viewpoint of DG Providers)

1) The determination that DG sales to an ESP are wholesale transactions subject to FERC jurisdiction has not been confirmed. If the determination is made that these wholesale transactions are subject to FERC jurisdiction, a ruling regarding this issue should be requested from FERC to exempt DG units under a particular size threshold from this burdensome and unnecessary requirement. Both PURPA and PUHCA identify exemptions regarding sales for resale.

2) Transmission charges are not applicable in all cases. The use of only the distribution system to sell excess DG to customers does not involve any physical use of the transmission system, particularly when the distributed generator and the customers are on the same substation and/or feeder. Consequently, OATT charges should not apply and Arizona electric restructuring rules may need to be adjusted..

3) A distribution wheeling charge should not be applied together with a distribution system access charge. The customer should be charged only once for use of the distribution system.

4) DG sales to other retail customers (UDC Viewpoint)

1) DG owners must become, or sell to, an ESP to sell excess power directly to other retail customers, and meet all ACC and local UDC ESP certification requirements.

2) DG owners attaining an ESP status would also be considered to be an EWG or IPP and must meet requirements under 18 C.F.R Part 365.

3) As an ESP, the DG owner must provide 100% of the load requirements for its retail customers (pursuant to the terms of Schedule 1 Section 3.5.2 as approved by the

d. Under this scenario, shareholders of the distribution UDC company will be required to absorb this reduction in fixed cost contribution and will not have an opportunity to earn a fair rate of return on their investment.

e. The derivation of distribution related stranded costs associated with the installation of DG must be quantified and recovered through use of one of the following methods:

1) A distribution stranded cost charge paid by the DG customer.

2) Redesign the current commodity based Standard Offer and Direct Access rates to include more fixed cost recovery of revenues (i.e. recover distribution related costs through a fixed distribution charge or contract capacity charge rather than a kW or kWh charges).

f. The rate design of SRP's large industrial tariffs, in conjunction with the standby electric service rider, is intended to recover fixed distribution facilities, distribution delivery, and transmission costs, based on the customer's reserved capacity on SRP's electric system. To the extent that DG becomes significant within the small business or residential classes, SRP may adjust current rate designs to accommodate that situation.

g. As discussed above, the rate design of SRP's large industrial tariffs, in conjunction with the standby electric service rider, is intended to recover fixed distribution facilities, distribution delivery, and transmission costs, based on the customer's reserved capacity on SRP's electric system.

h. To the extent that DG becomes significant within the small business or residential classes, SRP may adjust current rate designs to accommodate that situation.

9. DG Provider Concerns

a. DG providers recognize that UDCs are concerned over proper recovery of distribution assets, and their desire to move towards fixed-charge vs commodity-based recovery. However several concerns arise:

b. In the short-term, DG may cause under-utilization of the distribution system leading to the under-recovery of fixed distribution costs. In the longer term, the electric distribution UDC has the responsibility to promote system utilization that maximizes the available capacity of the system. Opportunity exists for increases in revenue recovery as system utilization is maximized and as new products are introduced by the regulated distribution UDC. The objective should be to facilitate and promote increased customer choice and greater competition.

c. There are several instances where the use of DG will not result in a reduction in the hours the distribution system is utilized.

d. The Settlement Agreement was entered into by APS with full knowledge that DG could potentially be utilized by customers. APS willingly agreed to a rate freeze. Additionally, Standard Offer and Direct Access rates could potentially be increased based on the provision in the Settlement Agreement that allows for rate increases based on conditions or circumstances which constitute an emergency. TEP also entered into a Settlement Agreement with full knowledge of DG and the Settlement Agreement contains the same provision for rate increases related to emergencies.

e. It has not been established that there will be stranded or unrecovered distribution-related costs directly related to the installation of DG. If there were any revenue deficiencies, including deficiencies due to the installation of DG, the distribution UDC has the opportunity to recover those revenues in its next general rate case.

f. Some UDCs have rate freezes or mandatory reductions in standard offer tariffs. Therefore any changes to the design of distribution tariffs for DG, without changing the tariff design for all customers and applications could be unfair and create an uncompetitive bias.

g. Reduces price signals for energy efficiency, which is being emphasized by some ESPs.

h. Could create rate shocks or windfalls for some customers.

i. May not be consistent with other customer situations in which load is reduced, e.g. energy efficiency, non-electric end uses, reducing business activity in an existing site, or sub classes of customers with unique load characteristics. UDCs are currently collecting commodity-based average distribution costs from these customer groups, even these activities reduce their contribution to the recovery or total distribution costs.

j. A distribution wheeling charge should not be assessed in conjunction with any distribution access charge. This is duplicative and requires a DG owner/operator to pay twice for the same service. A distribution wheeling charge, if any, should only be assessed against one party to the transaction. The appropriate party could be determined by where the ESP takes title or ownership to the excess power.

K. Metering

1. General

a. The Committee discussed various options concerning the metering of DG power. The requirements should depend on the size of the DG and whether the DG is selling excess power to the grid. For larger installations, which are selling excess power, the UDCs wanted to have hourly metered data. For very large installations, they desired dynamic (real time) data. DG providers generally concurred with real time data for DGs selling excess power; real-time data could be collected at the UDC expense.

a. Below is a review of metering options and recommendation by the UDCs and DG Providers.

2. Summary of Metering Options

a. Net metering (i.e. the meter running backwards). DG excess power sales to the UDC effectively offset customer purchases from the UDC. Could be time of use meter of monthly consumption meter.

b. Simultaneous buy-sell agreement. DG owners with on-site generation are required to sell 100% of their generation to the distribution UDC at avoided cost while purchasing 100% of their load requirements from the distribution UDC (or an ESP).

c. Traditional metering equipment with devices which prevent power to flow backwards through the meter. This would apply to DGs which are not intending to sell excess power.

d. Bi-directional metering equipment, which could facilitate excess power sales on a monthly-consumption, time-of-use or hourly-interval basis.

5. UDC Recommendations

a. Net metering (i.e. the meter running backwards) as a device is not well suited in a competitive environment and will not be offered to distribution generation customers.

b. DG owners with on-site generation will not be required to sell 100% of their generation to the distribution UDC at avoided cost while purchasing 100% of their load requirements from the distribution UDC (or an ESP). This situation is known as a simultaneous buy-sell agreement.

c. The installation of a bi-directional meter (either timed or un-timed) to record hourly sales to the customer and hourly excess power supplied to the distribution grid will be required for all distribution generation owners.

d. Excess energy sales to the customer and excess DG power supplied to the distribution grid will be separately metered and treated as separate transactions.

1) Hourly sales from the distribution UDC to the distribution generation owner will be priced at the applicable standard offer or direct access retail rate.

2) Any hourly excess DG purchased by the distribution UDC will be priced in accordance with an applicable standard offer partial requirements tariff (if available).

3) The distribution UDC will charge an appropriate distribution wheeling charge

for any excess distribution generation sold to an ESP.

c. SRP's Buyback Service Rider requires that the customer provide sufficient metering service entrances and pay for sufficient metering to segregate load between firm service and buyback service.

4. DG Providers Recommendations

a. DG providers concur that net metering would not be a typical metering solution, except perhaps for a special program for very small technologies, such as a residential solar program.

b. DG Providers generally concur that a bi-directional meter could typically be required for larger DG units that are selling excess power.

c. However, if the DG does not sell excess power, there should be no requirement for a bi-directional meter.

d. In addition, the pricing could be determined by contractual agreement between the DG and the UDC. The contract would determine the required metering equipment.

5. Ownership of information

a. UDCs and DG Providers agree that the ownership of metering and other related information concerning DG should be consistent with the ACC Competition rules.

B. Compensation for Grid Benefits of DG (Avoided Distribution Costs)

1. DG Provider Viewpoint

a. DG could provide avoidance of costs, as well as system benefits for the distribution UDC's distribution system. DG can provide many benefits to the distribution system as noted below. Additionally, there are many examples of DG applications that will result in the distribution infrastructure being used as many hours as it was originally anticipated.

b. Strategic placement of DG resources on the transmission or distribution systems can provide many system benefits to the distribution UDC. These benefits include improved system reliability, reduced transmission and/or distribution system line losses, the avoidance or deferral of transmission and/or distribution system improvements and upgrades, relief to constrained transmission and/or distribution systems, and environmental benefits depending on the type of technology employed and the type of fuel used.

3. UDC Viewpoint

a. In almost all instances DG will not provide any "avoided wires cost" unless the distribution system will never be used to provide backup power. If backup power is required for at any time, the local UDC must have the delivery system with adequate capacity to provide backup delivery service. The UDC must install the same distribution infrastructure if they are providing normal distribution delivery service or backup delivery service. The only difference is that the distribution system will be delivering less power and energy than originally anticipated.

b. Distribution facilities provide a customer with the option of purchasing electricity through the distribution company's wires. The cost to the distribution company / option value to the customer does not change because fewer electrons are flowing to the DG owner. A fixed "pipeline" of a certain size to the customer exists regardless, and the costs should be recovered.

c. Multiple distributed generators on a single feeder, if properly included in the original planning of the distribution system, could affect the sizing of the feeder. Specifically, the size of the feeder installation could be reduced due to the reduction in distribution load caused by the distributed generators, which have sufficient diversity in potential outages. There could be some "avoided wires cost" in this instance. Cases such as these would be infrequent and should be addressed on a case by case basis. Furthermore, the avoidable costs of the distribution system that can be avoided (such as smaller conductors) are typically small, relative to the fixed costs of distribution facilities such as distribution transformers and service drops.

Appendix a

ACCESS, METERING & DISPATCH COMMITTEE

Assigned questions and key topics

operations Subcoittee

Questions 4,5,6,7,8,9,10,11,12,13,15,16,17,21

topics

A set of operating scenarios were developed, with power generating entities defined as follows:

- System Support – Any DG that is operated for the principal purpose of bringing benefit or value to the system.
- End use customer only – Any DG, connected with the grid, that is operated for the principal purpose of self-generating to offset internal power consumption.

Disconnected from the grid – Any DG that is not capable of being interconnected with the grid, consequently for self-generation purposes ONLY.

1. UDC role, obligations for system management and interconnection
2. Jurisdiction issues for interconnection and control
3. Control of DG (UDC, CAO)
4. Relay requirements
5. Ancillary services
6. Disturbances, outages
7. Reliability issues
8. DG benefits to grid
9. Emergency generators
10. Metering requirements

Tariff And Policy subcommittee

Questions 1,2,3,13,15,18,19,20,22, sellback policy

topics

1. Distribution Costs
   Proper cost recovery in competitive environment
   Consistent and fair treatment for DG

2. UDC role/obligation
   Standby, maintenance power
   Supplemental commodity power
   Buyback excess DG power
   Tariff design – energy vs. monthly connection charges

3. PURPA issues

4. Selling DG power
   Over the fence (selling to neighbor)
   Self provision, multiple sites
   UDC grid vs. customer grid
   ESP role/obligation

5. Jurisdiction Issues

6. Net metering

7. Coordination policy
   Dispatch, control
   CAO scheduling
   Ancillary services

8. Value to grid

9. Information ownership and access

10. Tariffs
    Rules, policies
    Rate schedules
    Supplemental fees
    Maintenance fees
    Standby fees
    Buy-back charges
    Metering information

Compensation for benefits and costs to the system

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Appendix b

ACCESS, METERING & DISPATCH COMMITTEE

Members

	Contact	Representing	Telephone
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ORIGINAL

Arizona Corporation Commission
Distributed Generation Workgroup
Access, Metering, and Dispatch Committee (AMD)

Minutes from October 12.

Attendees

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Discussion

- The group discussed the potential impact of DG on grid operations and distribution design. The impacts were considered for specific DG applications shown in the first table below. After discussion, the issues were simplified to the cases shown in the second table. These case can also be explained in a tree diagram with the key determinants being (1) whether the DG application is connected to the grid (2) whether the customer is selling power back to the grid, and (3) the size of the DG unit.

- The tables were filled in to as far as the discussion carried.

(Table 1: all cases)

**distributed generation applications vs.
potential impacts on utility distribution grid**

Application	Potential Grid Impacts	Scheduling, Information Needs	Metering, Accounting Needs	Dispatch, Automation Needs	Distribution Design Issues
0-1 MW					
1-10 MW					
10+ MW					
Grid connected					
Sell to UDC					
Sell to ESP					
Self-use, multiple sites					
Emergency, backup					

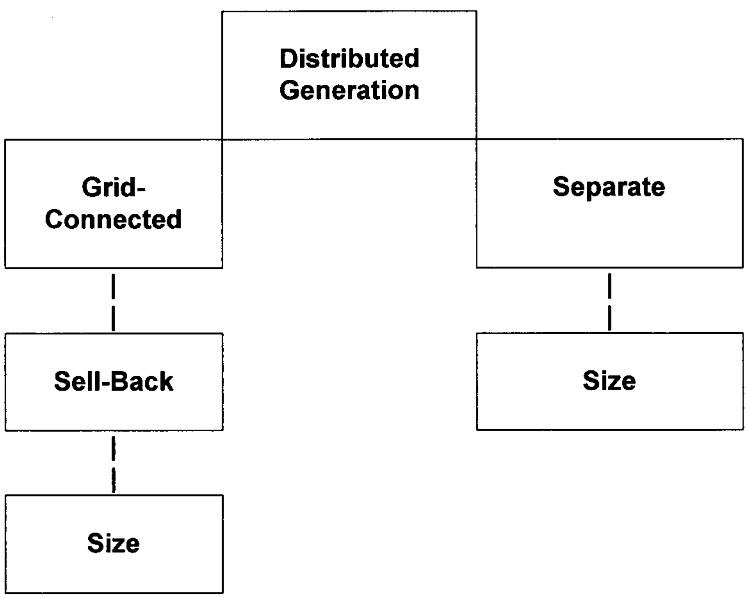
(Table 2: key cases)

distributed generation applications vs.
potential impacts on utility distribution grid

Application	Potential Grid Impacts	Scheduling, Information Needs	Metering, Accounting Needs	Dispatch, Automation Needs	Distribution Design Issues
Separate					
Grid connected					
Sell-back					
Size					

- Tree description of the operation impact issues

impacts on utility distribution grid



Operational Issues
Application 1: Separate from Grid

Application	Potential Grid Impacts	Scheduling, Information Needs	Metering, Accounting Needs	Dispatch, Automation Needs	Distribution Design Issues
Separate	None	X	None	None	X

Description

- DG is not connected to the grid;
- Typically used as emergency backup;
- Can be used for peak-shaving or other operation

Scheduling, Information Needs

- If a DG used for emergency backup fails, the grid would have to pick up the load during an emergency situation. Therefore Mapping of DG locations may be important because they may impact emergency feeder switching practices.

Distribution Design Issues

- For peak-shaving applications, if DG goes down and load is not separated from grid, then the grid will have to pickup the load.

- Adding baseload DG to an existing customer could cause load to drop below minimum level for a feeder, which could result in voltage regulation issues.

- Could be a design issue if the DG is a significant size relative to the circuit.

- Group discussed two possible rules of thumb:
  a. DG should not be over 50% of feeder capacity, without additional design considerations
  b. Aggregate DGs should not cause existing loads to drop below minimum load level for a feeder.

- If utility designs feeder capacity to accommodate the potential loss of the DG, then a distribution cost recovery issue.

Operational Issues
Application 2: Grid Connected (no sell-back)

Application	Potential Grid Impacts	Scheduling, Information Needs	Metering, Accounting Needs	Dispatch, Automation Needs	Distribution Design Issues
Grid connected	X	X	X	?	X

Description
- DG is connected to the grid;
- Customer is using DG for own site load, no load is intentionally being delivered or sold back to the grid.
- Could be used for a variety of applications including emergency, baseload, cogeneration, and peak-shaving.

Potential Grid Impacts
- Potential for load to lean on grid if DG goes down.
- Can use to off load for grid emergencies.

Scheduling, Information
- Some emergency applications run parallel when a storm is eminent to protect continuity of supply; they notify the utility by phone. Another notification system may be needed if the number of such applications increases significantly.
- May also need to map locations for same issue discussed under "Separate" case.

Metering, Accounting

Dispatch, Automation

Distribution Design
- Same issues under "Separate" case.
- Switching requirements

Operational Issues
Application 3: Sell-Back

Application	Potential Grid Impacts	Scheduling, Information Needs	Metering, Accounting Needs	Dispatch, Automation Needs	Distribution Design Issues
Sell-back					

Description

- DG is connected to the grid;
- Customer is selling power back to the grid or transporting power over the grid for use on another site.
- Could be used for a variety of applications including emergency, baseload, cogeneration, and peak-shaving.

Potential Grid Impacts

- Issue that CAO typically addresses transmission issues; distribution transactions may not be adequately considered.

Scheduling, Information

- Sales would typically have to be made to the UDC or to and ESP.
- Delivery of DG power over grid to another customer sight would have to be made through an ESP, unless a net metering program was set up for small applications.
- Grid sales above a certain size would have to be included in an ESPs schedule.

Metering, Accounting

- Sales to grid should be metered through an interval meter, at least above a size threshold.

Dispatch, Automation

Distribution Design

- UDC may need to know additional information, on top of the ESP schedule, on where the load is being put on the system, especially above a size threshold.

Operational Issues
Application 4: Size

Application	Potential Grid Impacts	Scheduling, Information Needs	Metering, Accounting Needs	Dispatch, Automation Needs	Distribution Design Issues
Size					

Description

Potential Grid Impacts

Scheduling, Information

Metering, Accounting

Dispatch, Automation

Distribution Design

Arizona Corporation Commission
Distributed Generation Workgroup
Access, Metering, and Dispatch Committee (AMD)

Minutes from October 20.

Attendees

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Discussion

- Committee discussed key tariff and policy issues concerning DG including:
  UDCs obligation to serve backup service for standard offer and direct access customers
  UDC cost recovery of distribution facilities
  UDC buyback of excess generation from DG

**distributed generation applications vs.
potential impacts on utility distribution grid**

Application	Potential Grid Impacts	Scheduling, Information Needs	Metering, Accounting Needs	Dispatch, Automation Needs	Distribution Design Issues
Separate					
Grid connected					
Sell-back					
Size					

Operational Issues
Application 1: Separate from Grid

Description

- DG is not connected to the grid;
- Typically used as emergency backup;
- Can be used for peak-shaving or other operation

Scheduling, Information Needs

- If a DG used for emergency backup fails, the grid would have to pick up the load during an emergency situation. Therefore Mapping of DG locations may be important because they may impact emergency feeder switching practices.

Distribution Design Issues

- For peak-shaving applications, if DG goes down and load is not separated from grid, then the grid will have to pickup the load.

- Adding baseload DG to an existing customer could cause load to drop below minimum level for a feeder, which could result in voltage regulation issues.

- Could be a design issue if the DG is a significant size relative to the circuit.

- Group discussed two possible rules of thumb:
  a. DG should not be over 50% of feeder capacity, without additional design considerations
  b. Aggregate DGs should not cause existing loads to drop below minimum load level for a feeder.

- If utility designs feeder capacity to accommodate the potential loss of the DG, then a distribution cost recovery issue.

Operational Issues
Application 2: Grid Connected (no sell-back)

Description
- DG is connected to the grid;
- Customer is using DG for own site load, no load is intentionally being delivered or sold back to the grid.
- Could be used for a variety of applications including emergency, baseload, cogeneration, and peak-shaving.

Potential Grid Impacts
- Potential for load to lean on grid if DG goes down.

- Can use to off load for grid emergencies.

Scheduling, Information
- Some emergency applications run parallel when a storm is eminent to protect continuity of supply; they notify the utility by phone. Another notification system may be needed if the number of such applications increases significantly.

- May also need to map locations for same issue discussed under "Separate" case.

Metering, Accounting

Dispatch, Automation

Distribution Design
- Same issues under "Separate" case.

- Switching requirements

Operational Issues
Application 3: Sell-Back

<u>Description</u>

- DG is connected to the grid;
- Customer is selling power back to the grid or transporting power over the grid for use on another site.
- Could be used for a variety of applications including emergency, baseload, cogeneration, and peak-shaving.

<u>Potential Grid Impacts</u>

- Issue that CAO typically addresses transmission issues; distribution transactions may not be adequately considered.

<u>Scheduling, Information</u>

- Sales would typically have to be made to the UDC or to and ESP.
- Delivery of DG power over grid to another customer sight would have to be made through an ESP, unless a net metering program was set up for small applications.
- Grid sales above a certain size would have to be included in an ESPs schedule.

<u>Metering, Accounting</u>

- Sales to grid should be metered through an interval meter, at least above a size threshold.

<u>Dispatch, Automation</u>

<u>Distribution Design</u>

- UDC may need to know additional information, on top of the ESP schedule, on where the load is being put on the system, especially above a size threshold.

Operational Issues
Application 4: Size

Description

- The committee discussed a variety of size demarcations for DG, which could determine the potential impacts on the distribution grid. The size categories were somewhat arbitrary, however, the Committee generally divided discussions into the following bins:
  - 0 - 300 kW
  - 300 kW - 1 MW
  - 1 MW - 10 MW
  - Above 10 MW

Potential Distribution. Operation and Design Impacts

- The size impact depends on several other factors: the capacity of the distribution circuit, proximity to utility generation source e.g. substation and whether the customer is served from a radial circuit, transfer switch, or spot network.

- The size issue also depends on the size of the DG relative to customer's service.

- The DG impact also depends on the operating hours of the DG relative to daily and seasonal peak of the feeder

- DG applications above 10 MW would typically be connected to the transmission grid, not the distribution grid. These applications would require individual project coordination with the utility, including grid impact studies and other informational needs. Given the customized nature of this category, it was not assessed in detail by the Committee.

- Utilities were concerned about DG applications above 1 MW, connected to the distribution grid. The capacity for most distribution circuits are in the 5 - 10 MW range, therefore, DGs above 1 MW can be significant relative to size of the circuit. These units could affect the operational issues discussed above, such as feeder capacity, emergency or seasonal switching, and minimum voltage issues.

- There was mixed discussion concerning DG applications in the 300 kW - 1 MW range. Potential impacts depend on the factors

- In general, the utilities had a lower level of concern for the 0-300 kW DG applications from a planning or operational perspective. The concern would increase, however, if multiple, small DGs were added to the same circuit, so that the aggregate generation became substantial.

Arizona Corporation Commission
Distributed Generation Workgroup
Access, Metering, and Dispatch Committee (AMD)

Minutes from October 25.

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Discussion

- Committee discussed key tariff and policy issues concerning DG including:
  - UDCs obligation to serve backup service for standard offer and direct access customers
- Selling excess DG power
- UDC cost recovery of distribution facilities
- Avoided wires costs from DG

Obligation to Serve (Backup and Maintenance Power)

Standard Offer Customers

- UDCs and DG Providers generally concurred that if the distributed generation owner chooses to be a standard offer customer, the distribution utility is obligated to provide back-up, maintenance, and supplemental power under the provisions of a partial requirements tariff

- APS already has these types of rates and related provisions in place. These rates would be applicable to any residential or non-residential customer requiring partial requirements services for distributed generation.

- TEP has QF tariffs but expressed the desire to modify these tariffs to conform with today's costs and market prices.

Direct Access Customers

- APS believed that the UDC is not permitted to offer back-up, maintenance, and supplemental power to distributed generation owners choosing direct access. They must contract for these competitive direct access services with a certified ESP.

- DG Providers believed that UDCs could have an option to provide these services to direct access customers.

Selling Excess Distributed Generation

Standard Offer Customers

- APS currently has standard offer purchase rates for qualified cogeneration facilities, qualified small power production facilities, qualified solar\photovoltaic facilities, and facilities utilizing renewable resources. Distributed generators meeting the requirements of a "qualified facility" under the provisions of the existing tariffs will be able to sell excess power to the distribution utility under the provisions of these tariffs.

- APS stated that any distribution utility elected buyback of distributed generation should be priced at the lower of the distribution utilities avoided cost or the hourly market rate. However, the UDC's current calculation of avoided cost will need to be based on market prices instead of the current methodology which is based on company-owned generation assets.

Direct Access Customers

- In general the UDCs believed that the distribution utility should not be required to buyback excess DG power. However, the distribution utility could elect to offer a distributed generation buyback service as part of a standard offer service (on an as needed basis with requirements, restrictions, and limits as determined by the distribution utility).

- DG Providers believed that UDCs could have options to purchase DG power for both standard offer and direct access customers. This could be part of the UDCs competitive procurement process for standard offer customers.

- UDCs generally believed that DG owners could not sell excess power to directly to other retail customers or sites unless they are an ESP. Distributed generation owners may sell excess power to an ESP.

- DG Providers agreed that this is probably the case under the current Competition Rules, however, this issue should be revisited as part of these proceedings.

UDC Recovery of Distribution Costs

- APS and TEP were concerned that they would under-recover distribution related costs from DG customers. They argued that the distributed generation owner will not be using the distribution system as many hours as was originally anticipated. Because the utility distribution company's current charges are commodity based, this causes a reduction in the revenues to be collected by the distribution utility without an equivalent reduction in costs. This distribution utility revenue reduction also reduces the fixed cost contribution to distribution plant, which is therefore under-recovered.

- APS and TEP expressed the need to design new partial requirements distribution rates for DG customers, which would collect distribution costs through a fixed charge, rather than the current commodity-based tariff.

- SRP expressed that their current unbundled tariffs are designed to adequately address this issue.

- DG providers expressed that there may not be a revenue deficiency. Absent significant market penetration by DG in a particular distribution UDC's service area, a revenue deficiency may be insignificant and could potentially, over time, be offset by revenues from distribution system load growth from new customers. Furthermore, the rate should be fair and reasonable and based solely on those costs actually incurred by the distribution UDC to provide the specific service. The rates developed should not act as a disincentive to the deployment and use of DG by customers nor should it be a direct subsidy for DG owners/operators.

- Some DG providers believe that a partial requirements, direct access tariff may not be necessary. The existing direct access tariffs could be used and any UDC distribution company revenue deficiency associated with the installation of DG could be recovered through the existing direct access rate structure. However, according to the UDCs, this implies that any revenue shortfalls will need to be recovered from other customers after rates are adjusted in a subsequent rate case. To ensure proper revenue recovery, the existing rate design will need to be modified to recover distribution system costs through customer charges, contract demand charges, and/or ratcheted demand charges instead of the current commodity based kWh charges.

1. Metering

The installation of a bi-directional meter (either timed or un-timed) to record hourly sales to the customer and hourly excess distributed generation supplied to the distribution grid will be required for all distribution generation owners.

(a) Net metering (i.e. the meter running backwards) as a device is not well suited in a competitive environment and will not be offered to distribution generation customers.

(b) Distributed generation owners with on-site generation will not be required to sell 100% of their generation to the distribution utility at avoided cost while purchasing 100% of their load requirements from the distribution utility (or an ESP). This situation is known as a simultaneous buy-sell agreement.

(c) All sales to the customer and excess distribution generation supplied to the distribution grid will be separately metered and treated as separate transactions.

   1) Hourly sales from the distribution utility to the distribution generation owner will be priced at the applicable standard offer or direct access retail rate.

   2) Any hourly excess distributed generation purchased by the distribution utility will be priced in accordance with an applicable standard offer partial requirements tariff (if available).

   3) The distribution utility will charge an appropriate distribution wheeling charge for any excess distribution generation sold to an ESP.

Chuck Miessner
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MEMO

DATE	October 11, 1999
TO	DG - Committee
RE	Minutes for committee meetings on 8/30 and 10/4.

Arizona Corporation Commission
Distributed Generation Workgroup

Access, Metering, and Dispatch Committee (AMD)
August 30, 1999 Meeting Minutes

Attendees

	Contact	Representing	Telephone	E-Mail
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	Operations Subcommittee			
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Agenda Items

- The AMD Committee was divided into two separate sub-committees: Tariffs and Operations.
- Chairs were selected as follows:
  Chuck Miessner – AMD Committee,

Steve Schmollinger – Tariffs,
Steve Bischoff - Operations

- Committee members volunteered for the subcommittees as shown above.

- Issues assigned to the Committee were reviewed and assigned to the subcommittees as follows:

	Assigned Issue Number
Tariffs	1,2,3,13,15,18,19,20,22, sell-back policy
Operations	4,5,6,7,8,9,10,11,12,13,15,16,17,21

- Discussed what the final output and report might look like.

- Discussed methods for reaching consensus on issues. However, Jerry Smith clarified that the main objective of the committee was to educate the Commission on key issues, potential solutions, and viewpoints from various stakeholders. That is, instead of trying to reach consensus or vote on each issue, we are to articulate both sides of the issues.

- Discussed homework for the sub-committees.

Arizona Corporation Commission
Distributed Generation Workgroup

Access, Metering, and Dispatch Committee (AMD)
October 4, 1999 Meeting Minutes

Attendees

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Agenda Items

- Chuck Skidmore gleefully volunteered to take notes for the minutes – thanks, Chuck!
- Dave Drummond provided a summary of the homework from the tariff sub-committee, see attached. The Tariff subcommittee met separately on 9/20 under the direction of Chairman Steve Schmollinger.
- Terry Linde provided a summary of the homework from the Operations sub-

committee, see attached. The Operations subcommittee met separately on 9/20 under the direction of Chairman Steve Bischoff.

- Reviewed information for final report to guide our discussions

Final Report

- ✓ Current situation
- ✓ Future perspective
- ✓ Key issues (utilities and implementers viewpoints)
- ✓ Priorities (primary, secondary)
- ✓ Ideas
- ✓ Best practices
- ✓ Pros & cons
- ✓ Actions and recommendations

- Reviewed distributed generation operation scenarios to guide discussions.

Scenarios

- ✓ Size (0-1 mw, 1-10 mw, 10+ mw)
- ✓ Stand alone (disconnected from grid)
- ✓ Sellback (utility, wholesale, retail) vs. self-use
- ✓ Cogeneration
- ✓ Standby, emergency
- ✓ Peak shave
- ✓ Power quality application
- ✓ Net metering

- Conducted broad discussion of operations issues and impacts with guests Jerry Smith of APS and Jerry Smith of the ACC-Staff. Summary of discussion:

  - Discussion largely centered around self-generators connected to the grid either for supplemental or backup power and the possible implications of those arrangements from both an electrical and a financial perspective. Those self-generators could be either Direct Access customers who buy power from an Electric Service Providers (ESP), or Standard Offer customers who buy power from the Utility Distribution Company (UDC) affiliate.

  - The group recognized that a clearer understanding or definition of Distributed Generation would be helpful for many committee members, discussions often migrate from one type of DG application to another, for which the operations and policy impacts are considerably different. The group reviewed the DG operation scenarios and tried to be clearer about which situation they were talking about.

- The group discussed their understanding of what exactly constitutes a distributed generator, both in general and specifically with regard to the ACC and the rules for competition.

- Generally Distributed Generation (DG) was talked about in terms of an electrical generator located near the end user or on site, with the primary intention of supplying power for the customer. The power could be baseload, peak-shaving, backup, emergency, or cogeneration. Excess power could be sold to the UDC, or to an ESP for the retail market. The latter could be intended for a retail customer such as a neighboring site which would not have to transmitted over the UDC power grid, or a noncontiguous site which would have to access the UDC grid.

- The group concluded that DG sales to other retail sites would have to be made through an ESP, as provided by the ACC competitive rules.

- DG can be grid connected or remote. The group concluded that Grid connected applications are a primary focus for the Operational subcommittee.

- ESP's can also build merchant generation and sell to one or several customers nearby. The group seemed to agree that, though the generator is certainly geographically distributed, it is a merchant plant and will be coordinated by the ESP. The ESP will coordinate through its Scheduling Coordinator with the Control Area Operator (CAO), Independent System Operator (ISO) or Independent System Administrator (ISA) depending upon how the grid eventually gets organized. Access, metering and dispatch issues are already being addressed. The group concluded that type of generation is not a focus for the DG workgroup.

- DG could also be used by the utility for local generation or grid benefits. The group discussed whether a UDC could own this type of DG or if the competitive rules required utility DG to be owned by an affiliated Genco. The group concluded that utility-owned DG is also not a primary focus of the committee.

- The rest of the discussion focused on DG which is grid-connected, located on or near the customer's site, and primarily intended for the customer's use.

- There are both technical and financial implications for the grid.

- If the DG unit is large enough, its operation could affect the grid. A number of similar DG's could have an aggregate effect, under certain circumstances, that could affect the grid even more. Communication about the operation of the DG would need to flow to the UDC, the ESP, and the CAO. The information flow would need to be rapid and accurate in order to allow the CAO to react to emergencies and unusual operating circumstances.

- Even though the original intent might not be to flow power from the DG to the system, it could happen. The DG could over generate and feed power into the grid. Depending upon the metering arrangement, the meter could flow backwards. This could have the effect of "selling" power back the grid. A savvy DG might be able to avoid penalties for drawing more power than he is allotted at one time but running the meter backwards to hide the excess use. Net metering could be used to advantage by the DG therefore net metering may be something that is not allowed.

- If Net metering is not allowed, should DG's have metering setups that will allow them to ship power to the grid free of charge? If they over generate, that would be there loss.

- Another possibility is that the CAO may want to tap unused DG capacity under certain circumstances. Should there be provision to allow this and if so, what compensation arrangements should be made?

- The DG could ship excess power backwards into the system specifically to sell it. Since the DG would not be an ESP it would have to use the ESP to broker the power. The ESP might, under certain circumstances, make use of excess DG to make up for shortages or take advantage of spot marketing opportunities. The book keeping could be difficult to track.

- Currently, under PURPA, cogenerators can sell electricity to the UDC at "avoided cost". Could such an arrangement work for the DG. Since the UDC is no longer in the generating business, the question arises as to how to value the "avoided cost". Also, if the DG never actually draws power from the distribution system but remains connected just in case, will the UDC be unable to properly recover stranded costs? Will the burden be unfairly shifted to those remaining users of the distribution system?

- Would a DG have to have a CC&N and be considered an ESP if the power generated were shipped through the grid to another DG owned site? To be sure the CAO would have to know it is happening and certainly the UDC should be paid for the use of its wires, but does the DG have the right to do this without having to satisfy all the same requirements that an ESP has to satisfy? If a DG were allowed to do this, what operational restrictions, metering and dispatch requirements should apply? Would the DG be required to pay imbalance charges and/or provide for ancillary services that might be required to maintain that balance?

- Could a collection of users joint venture to install a DG and ship power around the system to the members of the venture without having to become ESP's?
- If scenarios like 5&6 are allowed, who will coordinate with the CAO and schedule the power through the lines?

- **Next Meeting(s): Tuesday October 12th and Wednesday October 20th from 9:30 – 12:30.**

Operations Subcommittee
Homework Summary
September 20, 1999

Chairman, Steve Bischoff
Notes provided by Terry Linde

DATE/TIME:	September 20, 1999, 10:00 AM	**FILE NO:**	DGI–AMD-001
LOCATION:	1200 West Washington Street Phoenix, AZ	**WRITTEN BY:**	Terry Linde
SUBJECT:	ACC Committee Meeting Distributed Generation & Interconnection Committee Access, Metering & Dispatch Committee Operations Workgroup	**MINUTES OF MEETING NO.:**	001
		PROJECT NO.:	
PROJECT TITLE:		**DATE OF MEETING:**	September 20, 1999

PRESENT:

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OTHER DISTRIBUTION: Chuck Miessner (cmiessner@newenergy.com); Dave Drummond (ddrummond@newenergy.com)

1.0 For reference, the list of criteria that should be considered for each question to be evaluated, as developed during the earlier general session, are reproduced in this item below. INFO

For each question to be considered:

1.1 Brief description of the current situation

A look at what the future holds, from the perspective of:

- Utilities

Implementers

Identify issues & concerns

Establish priorities

- Primary

Secondary

Ideas & Concepts

Best Practices

Pros & cons

Action Items

1.2 The following is a list of potential operating scenarios and criteria that will influence the issues under consideration:

Combined heat & power (cogen)

Standby

Peak Shaving

Grid Support (private & utility)

Stand-alone (disconnected from grid)

Power Quality

Sell back (Utility/wholesale/retail/self use)

Size:

- 50kW & less

51-300 Kw

301kW-5MW

>5MW

Distribution versus Transmission level (5MW & less)

Control, dispatchable?

Certified / Non-certified

Net metering

Others (be mindful of potential issues)

AMD Operations Subcommittee Session

2.0 Steve Bischoff was chosen as interim chairman until a permanent chair is chosen. Members of the committee were encouraged to consider others within their organizations that might be suited and sufficiently available to assume this role. **All** 10/4/99

3.0 The set of workshop issues identified during the June 28th meeting, and assigned to the operations subcommittee appears below. During the September 20 meeting, the list of operations issues was listed in matrix fashion, as shown below. Each was assigned a "level of concern" rating, from the perspective of energy services providers and their customers.

The level of concern assigned to each issue is the highest rating that any interested party would assign to that issue (ie, an issue that may be of significant concern for one group, but less so for others will nevertheless receive a "high" rating). Ratings are "high" (H), "medium" (M), "low" (L) and "no concern" (N). Note that items labeled "N/A" were later eliminated from the list, on the basis that they were determined to be represented by other items on the list. See notes below.

The priority rating criteria is either "primary" (P) or "secondary" (S), and was assigned after discussion and assignment of levels of concern. An item received a "primary" priority rating if an "H" appeared in more than one column for that item.

Discussion relating to each of the items, in terms of the intent in listing the item as an issue, and the assignment of levels of concern, is recorded below the table.

Issue	DESCRIPTION OF ISSUE	LEVEL OF CONCERN			Priority (P/S)
		System Suppt	End use Customer	Disconn. From Grid	
4	UDC's total control a concern – Jurisdiction of all utilities for interconnections	H	L	N	S
5	Standardize equipment for monitoring and verification of interconnection **(metering issue)**	H	H	N	P
6	How will distributed generator customers contribute to ancillary service requirements	H	L	N	S
7	System dispatch / control for mutual system benefit	H	L	N	S
8	Management of / response to disturbances	H	H	N	P
9	More complex operational requirements when many distributed generators co-exist	H	H	N	P
10	Distributed generator load following capability	M	N	N	S

11	Real-time pricing affect on system dispatch and operation	L	L	N	S
12	Automation via supervisory control and data acquisition **(metering issue)**	N/A	N/A	N/A	N/A
13	Who should control distributed generator – Customer vs control area operator	H	H	N	P
15	If utility benefits from dispatch of units – How is customer / implementer compensated	H	H	N	P
16	Telemetry required for parallel operation (sell back) – **(metering issue)**	N/A	N/A	N/A	N/A
17	Distributed generator telemetry to send real time data to control area operator **(metering issue)**	H	M	N	S
21	Scheduling requirement	H	L	N	S

ITEM NO.	ITEM	ACTION	COMPLETION DATE
3.1	It was noted that, during the June 28th meeting, Issues 5, 12, 16 and 17 were originally assigned to the metering and telemetry subgroup, and then later absorbed into the operations group. The metering issues are identified in the listing above.	**Info**	
3.2	A set of operating scenarios were developed, with power generating entities defined as follows: • System Support – Any DG that is operated for the principal purpose of bringing benefit or value to the system. End use customer only – Any DG, connected with the grid, that is operated for the principal purpose of self-generating to offset internal power consumption. • Disconnected from the grid – Any DG that is not capable of being interconnected with the grid, consequently for self-generation purposes ONLY.	**Info**	
3.3	Issue 4 above relates to the implementers concern that UDC's may attempt to impose undue control over the DG's for their benefit. Conceivably, utilities could impose onerous interconnect requirements, effectively blocking new entrants into the service area. In the future world, control may be exercised by CAO's (Control Area Operator) separate from the UDC (Utility Distribution Center) level.	**Info**	
3.4	Issue 5 relates to the establishment of requirements for relaying, pre-certification of equipment through the establishment of a standard, and the development of a standardized connection agreement.	**Info**	
3.5	Issue 6, By being connected to the grid, distributed generators are a pool from which Ancillary Service Requirements might be drawn.	**Info**	

3.6	Issue 8, the CAO must make sure that there is no back-feed during disturbances. The End Use Customer is connected because at some point he expects to be drawing power from the grid.	**Info**	
3.7	Issue 9 concerns the relationship of the UDC within its obligations under its CCN and managing the system to meet the needs of interconnected parties.	**Info**	
3.8	Issue 10 is in the "noise level" for all but those providing system support. Others are managing self-generation to offset their dependence on grid capacity.	**Info**	
3.9	Issue 11 is intended to cover, from a wires perspective, operations and control area reliability, rather than a metering or tariff issue.	**Info**	
3.10	A lot of discussion was devoted to understanding the substance of issue 12, relative to how it's distinct from issues 13 16 and 17. The consensus of the group was that this issue relates less to the type of control and more to control of DG's in general by the UDC, tripping and safety issues, and costs incurred by the DG in the provision of this capability. At the conclusion of the discussion, it was concluded that this issue is adequately covered under issue 13. Issue 12 is consequently eliminated from further discussion, except for consideration as a subset of issue 13.		
	Ron Franquero to discuss this conclusion with Jerry Smith, to confirm that, in reaching this conclusion, we have not overlooked the intent of the committee in identifying this item as an issue.	Franquero	10/4/99
3.11	Issue 13 to include consideration of any issues associated with issue 12.	**Info**	
3.12	Regarding issue 15, it was noted that customer benefits are built into the rate structure, from the perspective that system investment (and therefore cost) is deferred with the addition of DG to the control area. The interconnection agreement, however, should anticipate and consider potential benefits from the addition of DG capacity to system stability and thereby avoid building disincentives to DG development into the agreement. Outage scheduling is one example.	**Info**	
3.13	Issue 16 was concluded to be a subset of issue 13 and therefore is eliminated from the list. As with issue 12, Ron Franquero to review with Jerry Smith.	Franquero	10/4/99
3.14	Issue 17 relates less to the "who" of controls, and more to the technical aspects of status and data reporting back to the UDC and control forward to the DG's. "Control" as it relates to Issue 17 is unique from issue 4, in that issue 4 relates to control from a system management perspective, rather than operational control.	**Info**	

4.0	**Where are we?**		
4.1	Based upon a review of the issues and level of concern table, the group concluded that we are only dealing with those DG's that are connected, or capable of being connected, to the grid. Every item in the column headed "disconnected from the grid" was determined to be of no concern to the rest of the parties interacting with the grid. "Emergency generators" are expected to be connected to the grid, ONLY for the brief period that they are operating after grid power is returned. (Sounds like we need to define "emergency generators")	**Info**	
4.2	Each issue requires review and homework to further prioritize it relative to the other issues. Each of the entities represented at the meeting were encouraged to "make a stab" at evaluating the issues according to the criterion identified during this morning's session (summarized in item 1 above), with emphasis on the first four, as follows: • Current situation Future picture Issues, concerns from utility, implementer, and customer perspective • Priority	**<u>ALL</u>**	10/4/99
4.3	Ways in which the objectives in item 4.2 can be accomplished are: • Investigate how the particular issue has been handled elsewhere, from a "best practices" perspective (other states in the process of deregulation, for example) Look at the issue from a control area perspective Utilize input from this meeting and reprioritize issues, prepare to review in detail at the next meeting.	**Info**	
4.4	Specific assignments will follow at the next subcommittee session.	**Info**	
4.5	ISO representation would be useful on this committee. The next AMD operations subcommittee meeting will be set to follow the general DGI meeting presently scheduled for October 4, 1999 at this location. Assume that the subcommittee meeting will commence in the afternoon, say 1:00 pm.	Franquero	10/4/99

Tariffs Subcommittee
Homework Summary
September 20, 1999

Chairman, Steve Schmollinger

Notes provided by Dave Drummond

The following issues were identified and targeted for further discussion and analysis. Subcommittee members should plan on discussing items 1 and 2 during the next meeting scheduled for October 4th.

1. Recovery of distribution costs
1. Utility obligation to serve
   a. standby
   a. commodity
   a. wires
   a. buying back
1. PURPA
1. Surplus sales
   a. over-the-fence (contiguous neighbor)
   a. at what price
   a. serving your own dispersed sites (UDC wheeling)
1. Jurisdiction
1. Net metering
1. Coordination/Scheduling
   a. dispatch
   a. value to Control Area Operator (CAO)
1. Value to the grid (benefits verses costs)
1. Information Ownership and Access
   a. ownership
   a. access
1. Tariffs
   a. rules
   a. policies
   a. rate schedules
   a. supplemental fees
   a. maintenance fees
   a. standby fees
   a. buy-back requirements/charges
   a. metering information
   a. compensation for benefits and costs to the system
   a. dispatch of the unit and conditions that trigger it

Arizona Corporation Commission
Distributed Generation Workgroup
Access, Metering, and Dispatch Committee (AMD)

Minutes from November 12

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Discussion

- Committee reviewed White Paper of UDC issues and submitted comments for Draft Report.

White Paper attached below.

ACCESS, METERING & DISPATCH COMMITTEE

KEY DISTRIBUTED GENERATION ISSUES

1. **Obligation To Serve**

   (a) Standard Offer Partial Requirements Service for Distributed Generation – APS & TEP

   1) If the distributed generation owner chooses to be a standard offer customer, the distribution utility is obligated to provide back-up, maintenance, and supplemental power under the provisions of a partial requirements tariff (APS already has these types of rates and related provisions in place). These rates would be applicable to any residential or non-residential customer requiring partial requirements services (distributed generation).

   1) The economics of partial requirements tariffs (both existing and proposed) will need to be addressed to ensure that the rates appropriately recover the costs associated with providing bundled partial requirements electric service to the distributed generation customer.

   (a) Distributed Generation Owners Choosing Direct Access – APS & TEP

   1) The distribution utility is not permitted to offer back-up, maintenance, and supplemental power to distributed generation owners choosing direct access. They must contract for these competitive direct access services with a certified ESP.

   1) The current direct access tariffs do not specifically address distribution delivery service to partial requirements (distributed generation) customers.

   1) Under the current direct access tariff structure, the rates charged a direct access distributed generation owner for any supplemental, backup, and/or maintenance power delivered are based on full requirements service. The installation of distributed generation reduces the number of hours the distribution system is being used by a specific customer and reduces the amount of revenues collected by the distribution utility under the provisions of the applicable direct access tariff.

   1) Utilities believe that a partial requirements direct access rate should be designed to properly recover distribution plant investment from customers utilizing distributed generation.

1) The City of Scottsdale brought up the fact that a partial requirements direct access tariff may not be necessary. The existing direct access tariffs could be used and any utility distribution company revenue deficiency associated with the installation of distributed generation could be recovered through the existing direct access rate structure. To ensure proper revenue recovery, the existing rate design will need to be modified to recover distribution system costs through customer charges, contract demand charges, and/or ratcheted demand charges instead of the current commodity based kWh charges.

(a) Single Tariff For Standard Offer and Direct Access Rates – SRP

1) SRP has a single set of unbundled tariffs, rather than separate standard offer and direct access rates.

1) SRP provides standby (partial requirements) service to large commercial and industrial customers served on the E-60 series price plans (over 1 MW and 300,000 kWh annually) under provisions of the standby electric service rider. The standby service rider applies to customers receiving electric service from SRP or an ESP.

2) The rate design of the E-60 series price plans with the standby service rider is intended to appropriately recover fixed costs from all customers based on cost of service, not just customers with DG. Rate designs may be examined and modified by SRP in future rate adjustments, but SRP would not likely decrease the level of fixed cost recovery in any future rate design change, unless such a change is supported by actual cost changes.

3) SRP does not have a tariff or rider to provide partial requirements service to residential or small business customers. If the market penetration of DG becomes significant within these rate classes, SRP may consider developing an appropriate tariff or rider.

4. Buyback of Excess Distributed Generation

The distribution utility should not be <u>required</u> to buyback excess generation. However, the distribution utility could <u>elect</u> to offer a distributed generation buyback service as part of a standard offer service (on an as needed basis with requirements, restrictions, and limits as determined by the distribution utility).

(a) Utility distribution companies currently have standard offer purchase rates for qualified cogeneration facilities, qualified small power production facilities, qualified solar\photovoltaic facilities, and facilities utilizing renewable resources.

Distributed generators meeting the requirements of a "qualified facility" under the provisions of the existing tariffs will be able to sell excess power to the distribution utility under the provisions of these tariffs.

(a) Excess distributed generation can not be considered firm power and may be supplied to the distribution grid at any time. This excess distributed generation is unscheduled and could be detrimental to the current loading on generation plants as well as transmission and distribution facilities. This affects the value of excess distributed generation to the distribution utility on an hourly basis.

(b) Any distribution utility elected buyback of distributed generation should be priced at the lower of the distribution utilities short-run avoided cost or the hourly market rate. However, in the near future, the UDC's current calculation of avoided cost will need to be based on market prices instead of the current methodology which is based on the utility's production costs.

(c) Under the current ACC competition rules and the APS settlement agreement, the distribution wires company will eventually be required to purchase generation for its standard offer customer through a competitive bidding process. To obligate a utility to purchase surplus power from a distribution generation owner would be detrimental to a competitive market and could increase costs to other Standard Offer customers.

(d) For the competitive market to function efficiently, the distribution generation owner, as a provider, should participate in the competitive bid process if they wish to sell excess or "merchant" power.

(e) SRP will purchase power from residential, commercial, or large industrial cogeneration and small power production customers under the provisions of the Buyback Service Rider. The buyback credit is indexed to the day-ahead hourly California PX prices for Palo Verde delivery less $0.00017/kWh, which is the cost to provide scheduling, system control, and dispatch services under SRP's retail Open Access Transmission Tariff.

6. Selling Excess Distributed Generation on the Open Market

Distributed generation owners can not sell excess power to retail customers unless the are an ESP (retail transaction). Distributed generation owners may sell excess power to an ESP.

(a) Distributed generation sales to an ESP

1) In accordance with Section 201 (d) of the Federal Power Act the sale of

electric energy at wholesale is defined as:

"a sale of electric energy to any person for resale."

1) Distributed generation sales to an ESP is considered a wholesale transaction subject to FERC jurisdiction. The distributed generation owner would need a market rate tariff (filed with FERC) to sell excess generation to an ESP.

2) OATT charges apply for all sales of excess power between the distributed generation owner and an ESP. Transmission charges can not be avoided if the ESP elects to sell excess distributed generation to customers located on the same substation or feeder as the Distributed generation unit in question.

3) If an ESP elects to purchase power from the distributed generator, an applicable FERC jurisdiction direct assignment charge for the distribution wheeling will apply. In order for the appropriate wheeling charge to be determined a direct assignment study will need to be done (in accordance with the provisions of the current OATT).

(d) Distributed generation sales to other retail customers

1) Distributed generation owners must become an ESP to sell excess distributed generation to other retail customers and meet all ACC and local utility ESP certification requirements.

2) Distributed generation owners attaining an ESP status would also be considered to be an EWG or IPP and must meet 18 C.F.R Part 365.

3) As an ESP, the Distributed generation owner must provide 100% of the load requirements for all the retail customers they are providing power to (pursuant to the terms of Schedule 1 Section 3.5.2 as approved by the ACC). This includes contracting for backup, supplemental, and maintenance power on behalf of these retail customers.

4) Retail customers contracting with the distributed generation owner for excess distributed generation will become Direct Access customers and take service under the distribution utility's applicable Direct Access rate.

5. Unrecovered Distribution Costs/Recovery of Fixed Cost Contributions

The installation of distributed generation after the area load has been established, and the delivery system has been installed, could lead to unrecovered distribution costs for the distribution utility. Our objective is to not subsidize distributed generation customers, either through utility shareholder or ratepayer funding.

(a) The distributed generation owner will not be using the distribution system as many hours as was originally anticipated. Because the utility distribution company's current charges are commodity based, this causes a reduction in the revenues to be collected by the distribution utility without an equivalent reduction in costs. This distribution utility revenue reduction also reduces the fixed cost contribution to distribution plant (which is unrecovered).

(b) Under the terms of the current Settlement Agreement, over the next five years distribution utility rates (both Standard Offer and Direct Access) will be decreasing and the distribution utility will not have the ability to increase existing Standard Offer or Direct Access rates. With fixed rate reductions the distribution utility will not be able to collect any reduction in fixed cost contribution associated with the installation of distribution generation for at least five years unless new rate designs are permitted . Any lost fixed cost contribution equates to unrecovered distribution costs.

(c) Under this scenario, shareholders of the distribution utility company will be required to absorb this reduction in fixed cost contribution and will not have an opportunity to earn a fair rate of return on their investment.

(d) The derivation of distribution related stranded costs associated with the installation of distributed generation must be quantified and recovered through use of one of the following methods:

1) A distribution stranded cost charge paid by the distributed generation customer.

2) Redesign the current commodity based Standard Offer and Direct Access rates to include more fixed cost recovery of revenues (i.e. recover distribution related costs through a fixed distribution charge instead of kW or kWh charges).

(c) The rate design of SRP's large industrial tariffs, in conjunction with the standby electric service rider, is intended to recover fixed distribution facilities, distribution delivery, and transmission costs, based on the customer's reserved capacity on SRP's electric system. To the extent that DG becomes significant within the small business or residential classes, SRP may adjust current rate designs to accommodate that situation

4. Metering

The installation of a bi-directional meter (either timed or un-timed) to record hourly sales to the customer and hourly excess distributed generation supplied to the distribution grid will be required for all distribution generation owners.

(a) Net metering (i.e. the meter running backwards) as a device is not well suited in a competitive environment and will not be offered to distribution generation customers.

(b) Distributed generation owners with on-site generation will not be required to sell 100% of their generation to the distribution utility at avoided cost while purchasing 100% of their load requirements from the distribution utility (or an ESP). This situation is known as a simultaneous buy-sell agreement.

(c) All sales to the customer and excess distribution generation supplied to the distribution grid will be separately metered and treated as separate transactions.

   1) Hourly sales from the distribution utility to the distribution generation owner will be priced at the applicable standard offer or direct access retail rate.

   2) Any hourly excess distributed generation purchased by the distribution utility will be priced in accordance with an applicable standard offer partial requirements tariff (if available).

   3) The distribution utility will charge an appropriate distribution wheeling charge for any excess distribution generation sold to an ESP.

(d) SRP's Buyback Service Rider requires that the customer provide sufficient metering service entrances and pay for sufficient metering to segregate load between firm service and buyback service.

5. Avoided Wires Costs

In almost all instances distributed generation will not provide any "avoided wires cost" unless the distribution system will never be used to provide backup power. If backup power is required for any time period, the local distribution company must have the distribution infrastructure to provide backup delivery service. The distribution wires company must install the same distribution infrastructure if they are providing normal distribution delivery service or backup delivery service. The only difference is that the distributed generation owner will not be using the distribution infrastructure as many hours as was originally anticipated.

Multiple Distributed Generators on a Feeder

Multiple distributed generators on a single feeder, if properly included in the original planning of the distribution system, could affect the sizing of the feeder. Specifically, the size of the feeder installation could be reduced due to the reduction in distribution load caused by the distributed generators. There could be some "avoided wires cost" in this instance. Cases such as these would be infrequent and should be addressed on a case by case basis. Furthermore, the variable costs of the distribution system that can be avoided (such as feeders) are typically small, relative to the fixed costs of distribution facilities such as distribution transformers and service drops.

1. Distribution System Planning

Using a detailed criterion, the Distribution System Planning Process is used to identify capital improvements that are necessary to maintain high quality, reliable, and safe electric service to our customers. The purpose of this section is to identify possible changes to the current Distribution System Planning Process precipitated by the addition of substantial amounts of distributed generation to the utility grid (assuming that most new generating facilities are distributed on the utility grid in small amounts).

(a) Facility Loading (transformers, wires, and, switches)

1) With substantial amounts of distributed generation connected to the system, facility loading would be determined by adding each distributed generation unit (watt and var output) to a computer model.

2) Two separate cases would probably need to be run (all distributed generation off-line and all distributed generation on-line). In the "all distributed generation off-line" case, we would still be required to supply the feeder load. Since we will still supply the total load, the distributed generation owners should be required to pay for this reserve capacity.

3) There would be no way of verifying the load flows because there is only one metering point at the substation bus.

4) There is pressure to keep the "permitting" time short (10 days or less) for new distributed generation installations. This may cause a problem if there isn't enough time to adequately study the different system configurations.

(e) Voltage profiles (from the substation to the end-of-line)

Voltage planning is required for the "peak" load case as well as the "minimum" load case since we have HIGH voltage and LOW voltage targets. The "all distributed generation off-line" case would be used to determine the feeder voltage profile during the "peak" load condition. The "all distributed generation on-line" case would be run during the "minimum" load condition.

1) Voltage control would be complicated because we would not be scheduling the DG units.

2) The Distribution utility would still be required to provide Power Factor correction for the "all DG off-line" case. Distributed generation owners should be required to pay for this reserve capacity.

(c) System protection (breakers, reclosers, sectionalizers, and fuses)

Depending on the size and location of the distributed generation unit, the distributed generator may back feed through a protective device causing a misoperation. Larger size distributed generation units may add to the system available fault current thereby exceeding the ratings of existing devices. In addition, larger distributed generation units would require "inrush" analysis to limit short-term voltage dip to other customers. All these conditions can be mitigated with the appropriate added system analysis.

(d) Contingency planning (load transfers)

Equipment failures, storms, dig-ins, and accidents typically cause most outages on the system. There would be NO reduction in the FREQUENCY of outages as a result of distributed generation additions to the system. In addition, the outage DURATION may be increased because repair time will be increased. In order to make repairs; the operations personnel will need to verify that no sources remain connected to the system. This must be done by observing a "visible" open switch.

The most difficult problem facing the operations personnel will be the feeder load transfer operation. When a block of load is to be moved from one feeder to another feeder all the above mentioned concerns must be addressed by field personnel.

The following questions will need to be answered by field personnel and/or engineering staff concerning any distributed generators:

1) Will the distributed generators be "on" or "off"?

2) What is the true load to be picked up by the secondary feeder?

3) How is the protection scheme effected?

The engineering staff can answer these questions after the appropriate analysis. But these questions will not be answered by the field personnel at 7:00 P.M. on a

Saturday Evening during a summer windstorm.

The current distribution system is a simple radial system. The addition of distributed generation to the current distribution system in effect creates a quasi-looped system. The transmission system is a looped system and as such requires ten times the amount of computer analysis as a radial system. Looped systems require a more complex computer program and require that all contingencies (load transfers) be modeled. In other words, the installation of distributed generation increases the level of complexity of the distribution system ten fold while at the same limiting control of the system components (distributed generation).

Arizona Corporation Commission
Distributed Generation Workgroup
Access, Metering, and Dispatch Committee (AMD)

Minutes from November 19

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Discussion

- Committee reviewed Draft report and submitted final changes. See Final Report.